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PROVINCE OF BRITISH COLUMBIA

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

SMALL HYDRO POWER RESOURCE IN THE PROVINCIAL SYSTEM

ECONOMIC AND FINANCIAL ASSESSMENT

SEL 5276
JULY 1983

SIGMA ENGINEERING LTD
ROBINSON CONSULTING & ASSOCIATES LTD

FOREWORD

The Financial and Economic Assessment of the provincial small hydro power resource was initiated as a logical follow-up to the Technology and Resource Assessment. In recognizing that small hydro would have to be an economically viable source of energy before it could replace or supplement traditional electrical energy supplies, the report was required to put the magnitude and importance of the resource in perspective.

At the time of writing the main body of the report (mid-1982), the comparison was made with the proposed Site C project near Fort St John on the Peace River. This project was the next in line in terms of BC Hydro's development plans, providing the lowest cost of energy for any of the foreseeable options for meeting provincial load growth. Accordingly, the small hydro resource was evaluated on the basis of being able to provide power at a comparable rate with Site C, in which case it could defer the need for Site C for at least several years and also provide a better match with provincial load growth. Off-grid small hydro resources were also compared with the cost of diesel fuel used for generating.

The current recession changed much of the thinking about provincial load forecasts. Electricity sales dropped and the long term load forecasts were revised downward. BC Hydro suffered operating losses and began to reduce staff. The commissioning of the Revelstoke project in 1984 with no immediate domestic need for its capacity worsens the situation. The Site C project has been deferred indefinitely and BC Hydro is making efforts to sell its surplus power thereby avoiding transferring the burden of higher operating costs to the consumer.

All of these factors may be considered negative in respect of the development of the small hydro power resource in British Columbia. However, it really means that additional time is now available in which to formulate policies for the development of the resource. The sites will not deteriorate nor will using electricity go out of style so the resource value will remain intact. The value of small hydro to replace diesel systems will continue to be attractive.

Despite the fact that many of the conditions present at the time of first writing the report have changed, the objective of the study is not diminished. A significant proportion of the resource has been determined to be viable in comparison with other sources of electrical energy, both for future expansions of the grid system and to replace diesel generation.

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1. INTRODUCTION

1.1 BACKGROUND

In order to assess the small hydro power resource in the provincial system, two complementary studies were commissioned by the Ministry of Energy, Mines and Petroleum Resources, and completed in July 1983.

The primary study was entitled, **Small Hydro Power Resource in the Provincial System, Technology and Resource Assessment**. (Reference 1). The status of the technology of small hydro power was reviewed and an inventory of 665 sites in British Columbia was provided. It is referred to in this report as the **Resource Assessment**.

Based on the limited data base of the study, these power sites appear to be technically feasible either to develop and connect to the integrated transmission system (referred to as on-grid sites) or to provide a supplementary power source in areas presently served by diesel generation (referred to as off-grid sites).

This study builds on the technical base provided in the companion report and assesses the economic feasibility and financial viability of the inventory of potential power developments.

BC Hydro presently operates eight hydro facilities with an installed capacity of less than 20 MW. However, the economies of scale provided by large hydro power schemes has tended to make further development of small hydro power too costly. Now the relative cost of constructing such generating facilities is rising as many of the low cost, environmentally acceptable sites have already been developed.

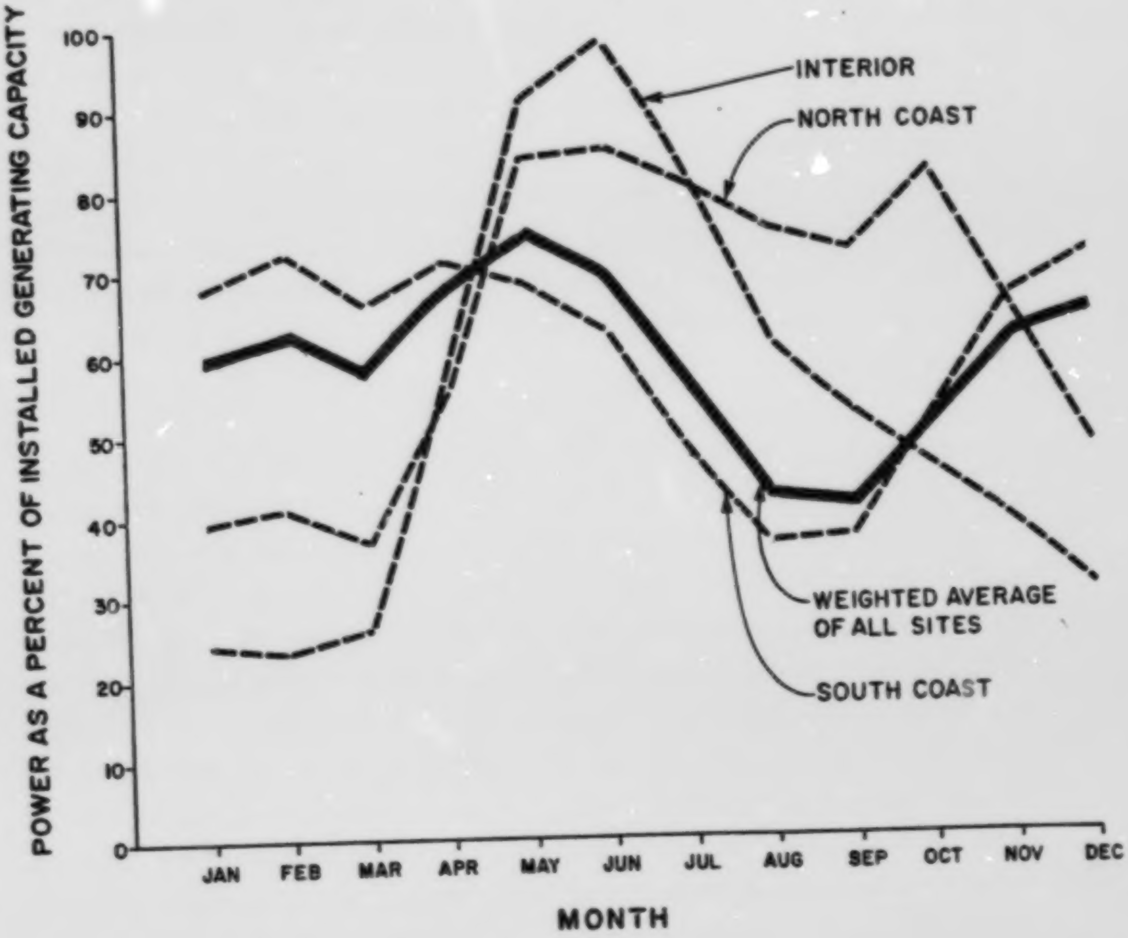
In contrast, the on-grid potential of small hydro power has been largely ignored and many of the relatively low cost sites are undeveloped. Hence the cost advantage of large scale hydro development has diminished relative to small hydro power in recent years. This, in part, explains the re-emergence of interest in the small hydro power resource.

The increasing awareness of the potential of the small hydro power resource is not confined to British Columbia. For example, the federal government is examining the potential for small hydro power to reduce the dependence of remote communities on imported oil (Reference 2/Reference 12). Further, in the United States, with the passage of the National Energy Act of 1978, small hydro power development (as well as a number of other alternative energy systems) became more attractive. In California alone, over 450 applications have been submitted to develop small hydro power (Reference 3).

1.2 OVERVIEW OF THE SMALL HYDRO POWER RESOURCE

The **Resource Assessment** identified sites that were within a reasonable distance of existing transmission lines or near diesel generating areas. With the aid of small scale contour maps and streamflow information, basins were analyzed and, if appropriate, projects conceived that had a capacity of less than 20 MW. This capacity limit was imposed so that the sites would fall within the streamlined application and approval process of the BC Utilities Commission. Within this capacity constraint, the plants were sized to be at full generation capacity for the mean annual flow of the particular stream. Most projects are run of the river plants. That is, the energy produced from a run of the river plant will fluctuate with streamflow. This seasonal variation in energy production is shown in Figure 1.1 for selected sites on the south coast, north coast and interior sites.

The energy production profiles are weighted averages of all sites in each region identified in the **Resource Assessment.** The production profiles result from the seasonal flow patterns in each region. In the south coast region, energy production averages in excess of 60 percent of installed capacity for seven months of the year. Energy production is greatest during the winter months when much of the precipitation falls as rain. This may be particularly important since electrical demand is generally the greatest during the winter season. Production falls to about 40 percent of installed capacity during the summer months when precipitation is at its annual low.



VARIATION OF SMALL HYDRO POWER CONTRIBUTION

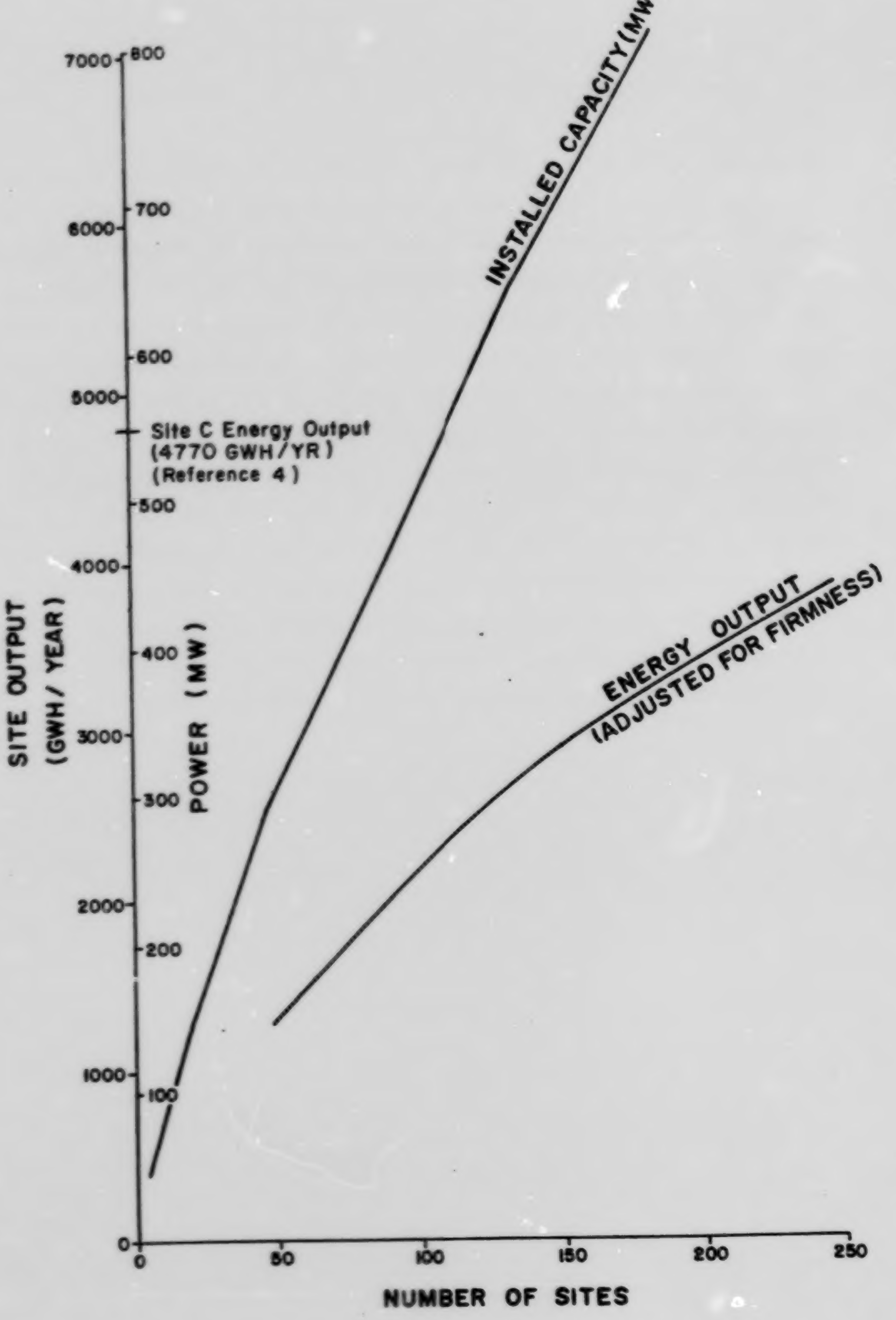
Note: Generator installed to use mean annual flow, run of river.

MEAN MONTHLY POWER OUTPUT AS A PERCENT OF INSTALLED GENERATING CAPABILITY vs. MONTH OF YEAR

FIGURE 1.1

The production profiles of the north coast and interior regions are different because a greater proportion of the precipitation falls as snow, which in turn effects stream flow patterns. In contrast to the south coast sites, the lowest production rates are in the winter months for these two regions. The impact of spring runoff is reflected in the higher production rates which reach maximum values during June and July. The influence of the spring freshet is dominant in the interior, where many of the sites reach production capacity during the same month (June). The north coast sites attain a second maximum during the late fall when the precipitation has not yet turned to snow. The weighted average production rates follow the general pattern of the south coast because about 70 percent of the technically feasible sites identified in the **Resource Assessment** are located in this region. The weighted average of all sites shows less variance than that of the individual regions, which is partly a result of the complementary regional production profiles.

From Figure 1.1 it is clear that the plants will be operating at less than full capacity during significant portions of the year. The **Resource Assessment** defined a 'firmness factor', which is the expected annual energy production of a plant divided by maximum possible production (installed capacity in kilowatts x 8760 hrs/year), and this factor was estimated for each site. The firmness factor would be numerically equal to the load factor for sites supplying power to an unlimited demand such as might be the case for supply to the integrated grid. The system load factor may be substituted for the firmness factor for off-grid sites with limited load when the plant output is limited by lack of water or lack of power demand. Note that the system load factor for a site will be less than or equal to the firmness factor because at times more power may be available than is needed. In general, the firmness factor is higher for coastal sites (average value of 0.6) than for the interior sites (average value of 0.5). Small hydro energy production from each site has been adjusted for firmness and it is on this supply of energy that the economic and financial analysis is conducted. The relationship between energy output adjusted for firmness and total installed capacity is illustrated in Figure 1.2.



QUANTITY OF SMALL HYDRO POWER
vs. NUMBER OF SITES

FIGURE I.2

3276

1.3 STUDY ORGANIZATION

This study builds on the cost data developed in the **Resource Assessment** in order to determine the economic feasibility and financial viability of the resource. For most of the 665 sites identified, the **Resource Assessment** provides capital and operating cost estimates. Although technically feasible, the cost of developing the energy potential of many of these sites may exceed the cost of energy from an alternative source. That is, particular sites may not be economically feasible. The economic value, as well as a consideration of the planning flexibility offered by the small hydro power resource is addressed in Section 2. It may be the case however, that a site is economically feasible from the social perspective, but the financial returns to a private developer would not justify the investment. In Section 3 the minimum financial rewards necessary to develop the economic potential of the resource are considered. In Section 4, the effects of existing and potential public policies for promoting development of the resource are considered. In Section 5 the Conclusions and Recommendations of the economic and financial assessment are presented.

2. ECONOMIC ASSESSMENT OF THE SMALL HYDRO POWER RESOURCE

The objective of this component of the study is to assess the economic feasibility of 612 (1) small hydro power sites identified in the Resource Assessment. Economic feasibility is defined in terms of the cost of developing a particular site relative to the cost of developing the next best energy source. The next best energy source (for on-grid applications) was taken to be one of several major hydro power projects under study by BC Hydro. A small hydro power site is deemed to be economically feasible if its average cost per unit of output is less than or equal to the equivalent cost from the next major hydro power project developed in British Columbia.

In Section 2.1, the categories of costs affecting the small hydro power resource are discussed and the total costs of developing the resource are presented. In Section 2.2, the cost of meeting future electricity requirements through delaying or avoiding the need for the construction of major projects is estimated and compared to the cost of developing the potential on-grid small hydro power sites. The economic feasibility of off-grid sites is presented in Section 2.4 following a review of sensitivity analysis in Section 2.3.

Before beginning the detailed discussion, those features distinguishing the economic and financial analysis should be noted. The economic analysis adopts a more broadly defined referrant group than the financial analysis and uses the social opportunity cost concept instead of market prices; whereas the financial analysis proceeds from the perspective of the private investor, the economic analysis is from the perspective of the society. The social opportunity cost of an economic resource is its value in its next best alternative use, which may or may not correspond to the prevailing market prices. For the most part, the analysis takes market prices as an adequate measure of the social opportunity cost of developing the resource. The one important exception is the value of electricity, which is estimated as the sum of the costs of production rather than the regulated prices under which electricity is actually sold.

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(1) Of the 665 sites included in the **Resource Assessment**, there was not enough detailed information available on 53 sites for economic evaluation. The remaining 612 form the basis for the economic assessment described in this Section of the report.

2.1 COSTS

Project costs appropriate to the economic analysis are the consumption of economic resources (materials, goods and services) over the life of the project. Costs that are relevant in the financial analysis but do not represent a use of resources, such as depreciation and taxes, are specifically excluded. The opportunity costs of the resources are taken at the respective 1982 prices. The analysis excludes inflation and further, it is assumed that capital and operating costs will remain constant in real terms over the forecast period. Inflation, which is a rise in the general price level, does not affect relative prices. It can be excluded from the economic analysis without affecting the results. Also included in the economic assessment are costs not necessarily borne by the developer but which are nevertheless incurred by the provincial society. Examples might include affects on downstream users, and impacts on other watershed users. Effects of this nature are site specific, hence can only be assessed qualitatively at this level of study.

The major cost categories are considered below before the cost information on the 612 sites evaluated is presented.

Capital Costs

Capital costs include the expenditures for plant and equipment, transmission line and access road. The costs were taken directly from the **Resource Assessment.** The estimates include an escalation factor that takes account of the generally higher construction costs of remote sites. To simplify the analysis, each site was considered as a stand alone project whereas capital cost savings could be realized if several sites were developed together thus sharing the transmission line and the access road.

The penstock is typically the single most costly capital item of a small hydro power facility, making up approximately 20 - 60 percent of the installed plant and equipment costs. Plant capacity was sized to the estimated average annual flow of the stream. The access road cost was estimated as a function of length and the size of plant. The cost of the transmission line depends on length as well as the appropriate rating of the line (12 kV to 138 kV lines). Consistent with the level of detail available in the **Resource Assessment**, each project was optimized in terms of minimizing plant costs while meeting particular performance and reliability criteria.

A contingency factor of 30 percent was included. The costs of land, rights-of-way, and the interconnection facility (for on-grid sites) were not specifically included. However, these costs are expected to be relatively modest compared to the cost of other components, and are, for the purposes of this study, included in the contingency category.

Capital cost analysis methods used in the **Resource Assessment** are described in more detail in Appendix 4.

Operation and Maintenance

The operation and maintenance costs depend on the size and operating characteristics of the plant as well as the operation requirements of the owner/operator, and the utility (on-grid). The estimates included here assume a relatively high degree of automation; also that several sites would be developed and operated simultaneously. Operation and maintenance costs were estimated at 1.2 percent of the installed capital costs and remaining constant (net of inflation) over the project life (50 years). If a full time operator were required on-site, then the annual charge would be in the order of 2 - 4 percent of installed capital cost. It should be noted that because taxes (corporate income tax, property tax, etc) and water rental fees do not represent a draw on real economic resources they were not included in the operating expenses.

Transmission and Downtime Losses

Included in this category are the power losses in transmission which depend on line length and capacity, and annual energy generation reductions due to periodic plant outages and closures for maintenance. These losses were anticipated to be in the order of 10 percent of gross annual production. For the on-grid sites, this is the net energy assumed to be delivered to the grid.

Non-Quantifiable Costs

The effect of the typical run-of-the-river small hydro project on other watershed uses is expected to be minimal. The nature of the facility requires the penstock to be located on a relatively steep gradient where stream flow velocity typically exceeds that favourable for fish habitat. Valuable scenic attributes of a particular watershed may be reduced during periods of low flow if the stream is largely dewatered between the penstock and tailrace.

More significant impacts may arise from interdependencies with forest harvesting and related activities. Road building and logging may increase the debris and sediment load in the stream, thereby affecting facility operations such as increased wear on turbines and penstock. In addition, the post-logging discharge of the stream may be altered (increased peak flows and reduced low flows compared to pre-logging discharge) which could decrease the total energy production of the plant. These effects can be reduced by altering forest activities (changing road alignments, green strips beside the stream, adjusting the cutting plan, etc) which would typically increase forestry costs. In practice, the conflict would likely be resolved with reference to current logging practices and through negotiations between the two parties. Nevertheless, the incremental costs arising from the interdependency is acknowledged in the social benefit-cost framework regardless of which party bears the costs. At this level of study, sufficient information was not available to estimate the magnitude of this cost.

Total Costs

The total quantifiable cost of small hydro power is the present value sum of the capital and operating costs. Future annual costs are converted into 1982 present value equivalents using an 8 percent real discount rate (the recommended rate according to the revised Provincial Benefit-Cost Guidelines).

To provide a clearer understanding of the costs of developing the resource, and to facilitate the economic feasibility analysis, the equivalent non-inflated cost of power was computed for each site in each of three regions.(1) (Appendix 1 contains the total cost per kW.h computed for each site and Appendix 1 of the **Resource Assessment** contains a printout of site costs and site characteristics). The cost varies significantly among sites ranging from 20 to 400 mills/kW.h. In Figure 2.1, firm energy supply has been arranged from the lowest cost to the highest cost sites. The south coast region contains many of the low cost sites, followed by the interior and north coast regions. The regional curves are summed horizontally (ie. for a given cost, the energy from the regions are summed) to yield the energy supply curve for the total resource. Since the energy production is adjusted for firmness, the supply of energy at the respective costs represents potentially available energy.

Figure 2.1 forms the basis for the economic feasibility assessment described in Section 2.2 and Section 2.4 where the average cost of on-grid and off-grid small hydro power applications is arrayed in the same manner as Figure 2.1. Figure 2.2 presents the regional distribution of the less costly sites. Note that a very large proportion of the less costly sites are located on Vancouver Island and the Lower Mainland.

Figure 2.1 summarizes a great deal of useful information. It represents the long run supply of small hydro power capacity. That is, for a given average cost of energy of an alternative source, Figure 2.1 provides an estimate of the small hydro power capacity that would be less costly to develop if unconstrained by institutional, financial, and other considerations. In the next section, the cost of alternative energy sources is estimated and compared to the cost of developing small hydro power in order to define the economic feasibility of the resource.

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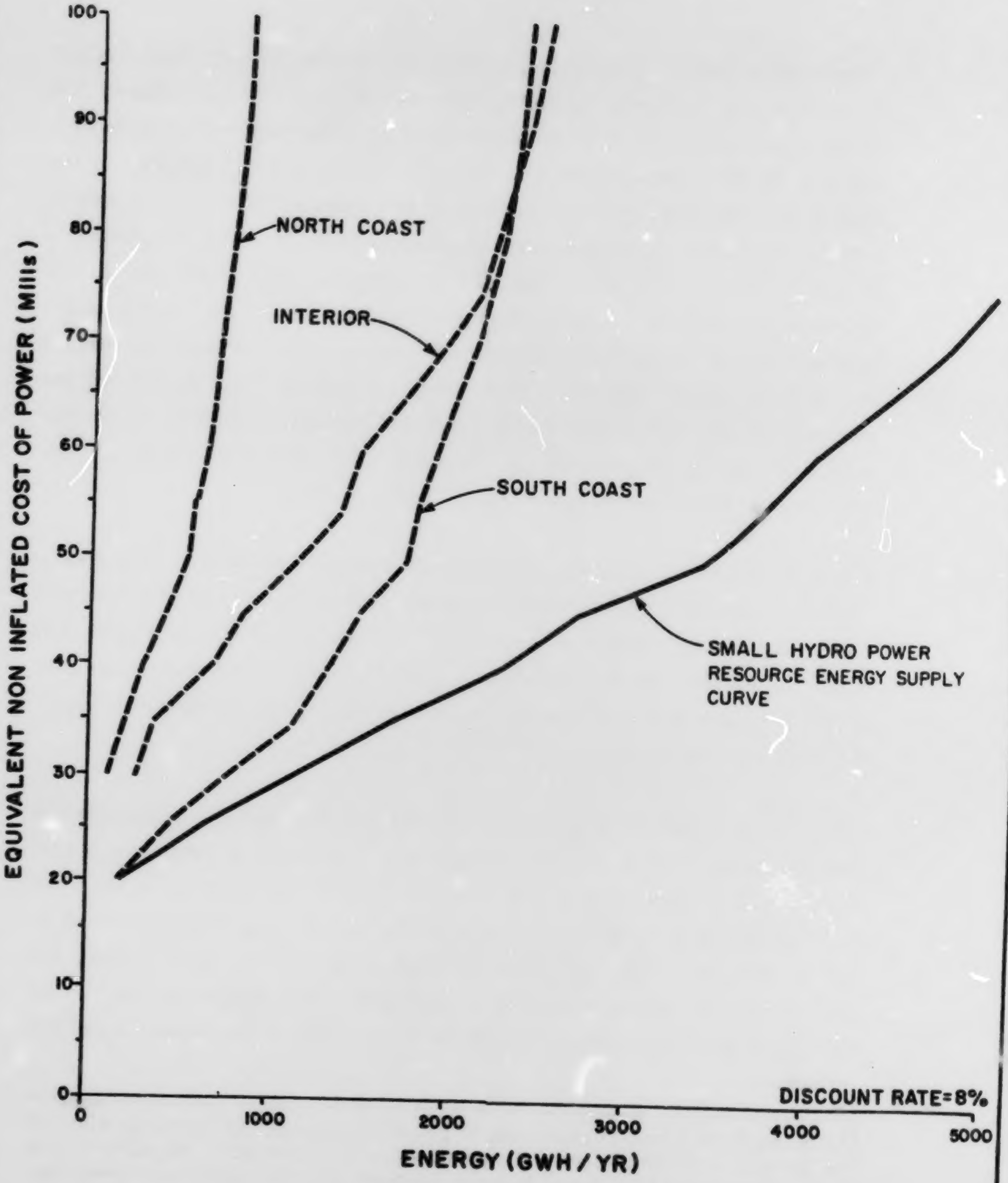
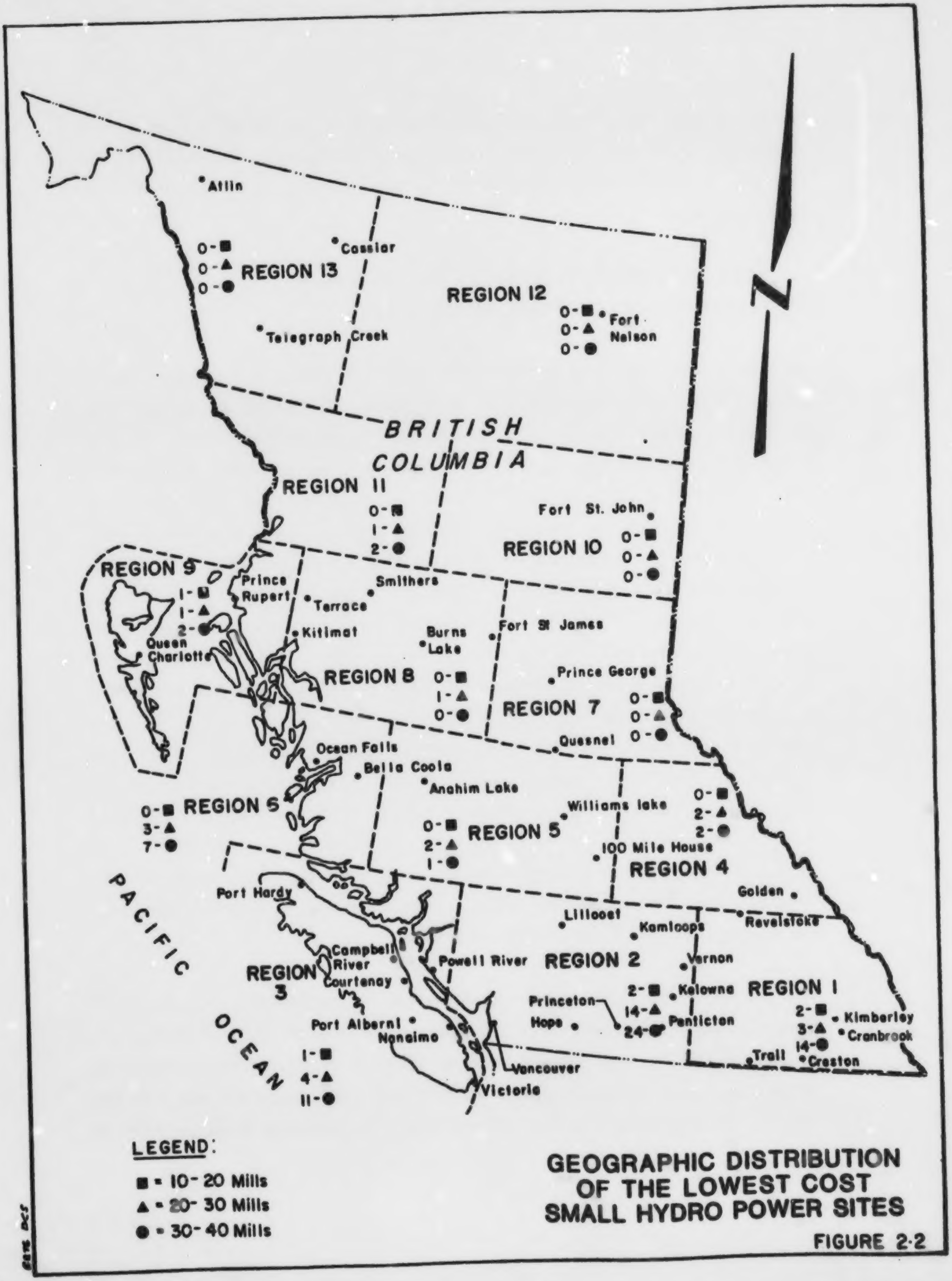
(1) The equivalent non-inflated cost of power was computed as the quotient of the present value total cost and present value net electricity production. The cost estimates differ from those presented in the Resource Assessment because: (a) operation and maintenance costs and transmission line costs are included; (b) allowance is made for electricity losses due to transmission losses and periodic shutdown; (c) an 8% discount rate and a 50 year project life was assumed rather than a 5% discount rate and an infinite project life as adopted in the Resource Assessment.



SMALL HYDRO POWER RESOURCE INCREMENTAL ENERGY CAPABILITY vs. INCREMENTAL COST OF POWER

FIGURE 2.1


Atlin
Cassiar
Telegraph Creek
REGION 13
0-■
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REGION 12
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0-●
Fort Nelson
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BRITISH COLUMBIA
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Fort St. John
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Queen Charlotte
Prince Rupert
Terrace
Smithers
Kitimat
Burns Lake
Fort St James
Prince George
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Quesnel
Ocean Falls
Bella Coola
Anahim Lake
Williams lake
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100 Mile House
REGION 4
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Golden
Revelstoke
Port Hardy
PACIFIC OCEAN
Lillooet
Kamloops
Campbell River
Courtenay
Powell River
REGION 2
Vernon
REGION 3
Kelowna
Princeton
Hope
2-■
14-▲
24-●
Penticton
REGION 1
2-■
3-▲
14-●
Kimberley
Cranbrook
Trail
Creston
Port Alberni
Nanaimo
1-■
4-▲
11-●
Vancouver
Victoria
LEGEND:
■ = 10-20 Mills
▲ = 20-30 Mills
● = 30-40 Mills

GEOGRAPHIC DISTRIBUTION
OF THE LOWEST COST
SMALL HYDRO POWER SITES

FIGURE 2-2

Notwithstanding the conclusions reached in Section 2.2, Figure 2.1 provides a simple and comprehensive means for assessing the economic feasibility of the resource in light of the changing energy requirements and opportunities in British Columbia.

2.2 THE ECONOMIC BENEFITS OF SMALL HYDRO POWER DEVELOPMENT AND ECONOMIC FEASIBILITY

As noted earlier in Section 2, the economic value of small hydro power output is the cost (saved) of an alternative energy source. This value will be different depending on the perspective of the developer as well as the characteristics of the output. For example, the value of small hydro power to industry, or to a community served by a diesel plant, is the cost savings of displacing purchased electricity (industry) or fuel cost savings (community). For the private developer, the value of small hydro power output is its selling price. This latter perspective is assessed in Section 3. From the broader provincial point of view, the value of small hydro power output is the cost savings realized from displacing the next best alternative cost energy source. We have assessed the economic value of the small hydro power resource from the latter perspective.

The value of the energy output is also related to how "dependable" it is. That is, whether the energy is always available when it is required. Output of this nature has a "capacity value". If, on the other hand, the output is available independent of system requirements, then the value corresponds to the most costly fuel displaced at the time the output is available. This is termed the "energy value". Because of the nature of the small hydro power resource, only the energy value was attributed to the output.

A small hydro power development is defined to be economically feasible if the present value of the output exceeds the present value of all costs of production. In Section 2.1 the total present value of all costs of production is presented without regard to either on-grid or off-grid potential. Since the value of the output differs between the two applications, this distinction must be made to establish economic feasibility. In this section the economic feasibility of on-grid applications is considered. In Section 2.4, the off-grid assessment is considered.

The average value of on-grid energy will be estimated first in terms of mills per kW.h. This value is then compared to the costs of developing the sites that could possibly be grid-connected to determine economic feasibility. A similar procedure is followed in assessing the economic feasibility of off-grid applications.

On-Grid Small Hydro Power Assessment

The **Resource Assessment** identified 521 sites that could possibly serve the integrated grid and which had sufficient information for cost analysis. The average cost of the sites ranges from 22 mills to 325 mills per kW.h (Figure 2.3); 206 of these sites are on the south coastal area of the mainland and Vancouver Island; 53 are located in the Bella Coola area and the north coast; and 262 are located in the interior. Total potential installed capacity is estimated at 1,217 MW although only part of this could be considered cost competitive relative to large scale hydro power alternatives.

The economic value of energy output to the integrated electrical grid is the equivalent cost of energy displaced from the highest cost source in the system. In a "mixed" hydro/thermal system, the savings would be the fossil fuel cost saving from thermal generation. However, the provincial system is predominantly a hydro power system.(1) Once a hydro power plant is in place, the annual operating costs are low. This value is well below the average cost of production from even the least costly small hydro power site. That is, the development of small hydro power to displace energy produced from existing facilities is probably not economically feasible. Similarly, the capital cost of the nearly completed Revelstoke Project is "committed", so that the value of displacing incremental energy over the near term is also very low.

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(1) The Burrard Thermal Plant is operated during peak periods and critical low flow years. Although energy from this facility might be the highest cost, potential output from small hydro power does not have the same performance characteristics, hence it is considered that one is not a substitute for the other.

With the commissioning of the Revelstoke Project (in 1984), the firm generating capacity of the B C Hydro system will be approximately 10,190,622 kW. This capacity is expected to be sufficient to meet domestic firm energy requirements until 1991 and perhaps later, depending on the load growth forecast considered.(1)

At some point in time, however, system expansions will be required to meet the growth in provincial energy requirements. Since the capital expenditures of these future projects are not committed (that is still an avoidable cost), it is appropriate to express the value of small hydro power output as the cost of production from a future conventional hydro power plant.

Although electricity is produced by Alcan, MacMillan Bloedel, West Kootenay Power and Light, and B C Hydro, future electricity requirements will likely be primarily met by additions to the B C Hydro system. B C Hydro has a series of hydro power facilities under study to meet provincial energy requirements over the next twenty years (Reference 4). The Peace Site C project is the most advanced in terms of planning with a tentative in-service date of February 1991.(2) Other projects include the Murphy/Keenleyside, Liard, Iskut Canyon, and the Stikine. The average energy costs from each of these projects, as well as several others, are presented in Figure 2.3 along with the cost of developing the on-grid small hydro power sites in the three regions.

The economically feasible small hydro power sites are defined as those of average energy costs that are less than or equal to the average cost of the alternative project. With regard to Peace Site C, there are 54 sites with an installed capacity of 300 MW that can provide energy at lower costs. Compared to the Murphy Creek/Keenleyside Project, there are 84 feasible sites with an installed capacity of 430 MW. According to the **Resource Assessment**, the 54 sites would provide 1,370 GW.h/year of energy which represents 2.3 years load

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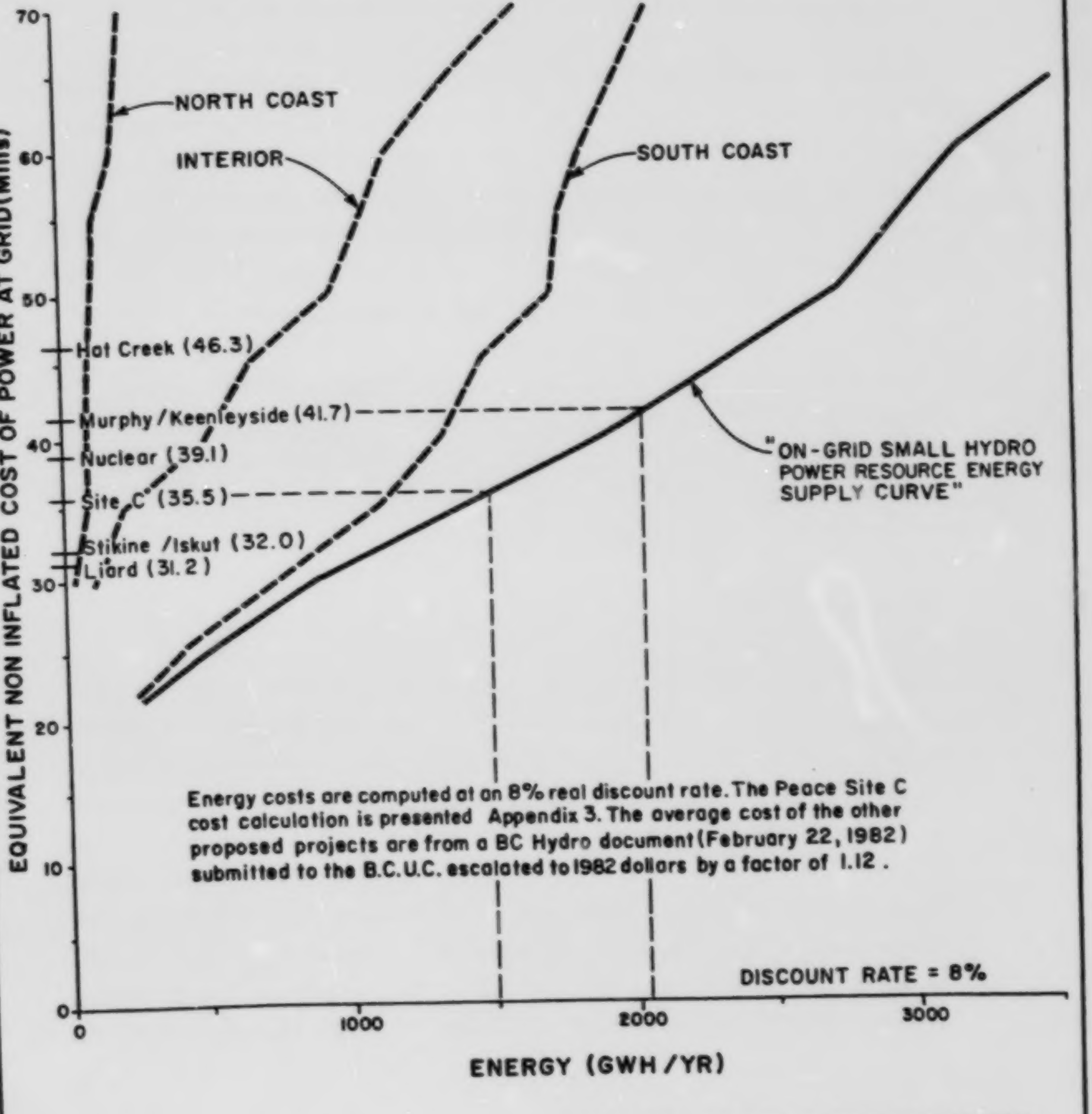
(1) See Appendix 5 for a discussion of assumptions regarding B C Hydro system and power demand forecasts.

(2) B C Hydro has applied to the BC Government for an Energy Project Certificate. The decision regarding the terms and conditions of a certificate was still under consideration when this study was prepared.



Energy costs are computed at an 8% real discount rate. The Peace Site C cost calculation is presented Appendix 3. The average cost of the other proposed projects are from a BC Hydro document (February 22, 1982) submitted to the B.C.U.C. escalated to 1982 dollars by a factor of 1.12 .

ON-GRID SMALL HYDRO POWER
INCREMENTAL ENERGY CAPABILITY
vs. INCREMENTAL COST OF POWER
(At point of grid connection)

FIGURE 2.3

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growth assuming the most recently available load forecast by the Ministry of Energy, Mines and Petroleum Resources (MEMPR) (Reference 6). The 84 sites would provide 1,970 GW.h/year and contribute 3.0 years of load growth.

There are two other aspects of small hydro power that may affect its economic feasibility. Firstly, there may be lower transmission losses associated with small hydro power production compared to conventional hydro power because small hydro power feeds into lower voltage lines on the grid, which tend to be closer to the consumer. Note that many of the economically feasible small hydro power sites are located in the south coast regions which contain the largest population centres. Figure 2.3 compared the average costs of conventional hydro power at the **plant site** to small hydro power at the grid **connection**. In the following analysis, the costs of energy will be compared at a common point which is taken to be a **residential customer**.(1) Secondly, the incremental nature of small hydro power offers an economic savings as well as planning flexibility. These two aspects of the small hydro power resource are considered in the following sections.

Transmission Losses

There are a number of factors which interact to determine the proportion of generated energy lost on route to the final user. For the entire BC Hydro system, these losses are in the order of 10 percent of the generated energy. However, losses attributed to serving customers at particular voltage levels are much higher than the system average. Incremental loss multipliers, which represent average values for the BC Hydro transmission system are presented in Table 2.1. The secondary voltage level refers to residential and general service (single phase 60 hertz, at secondary potential). In order to deliver 1 kW.h of energy to the final user, 1.4279 kW.h must be produced at the generating station (assuming average operation at 75 percent of peak capacity and initial transmission at 500 kV). In contrast, many of the small hydro power sites would be connected into the grid at 25 kV (primary voltage). Small hydro power cannot economically connect into a transmission line greater than 138 kV because the size of the plant (that is less than 20 MW) does not justify the expense. Hence, a greater proportion of the energy produced from a small hydro power site may be available when serving a residential customer.

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(1) The lower voltage delivery points on the grid tend to be associated with higher losses because of the lower efficiency of transmission at lower voltages. The assumption of delivery to a residential customer therefore is a case where losses are highest.

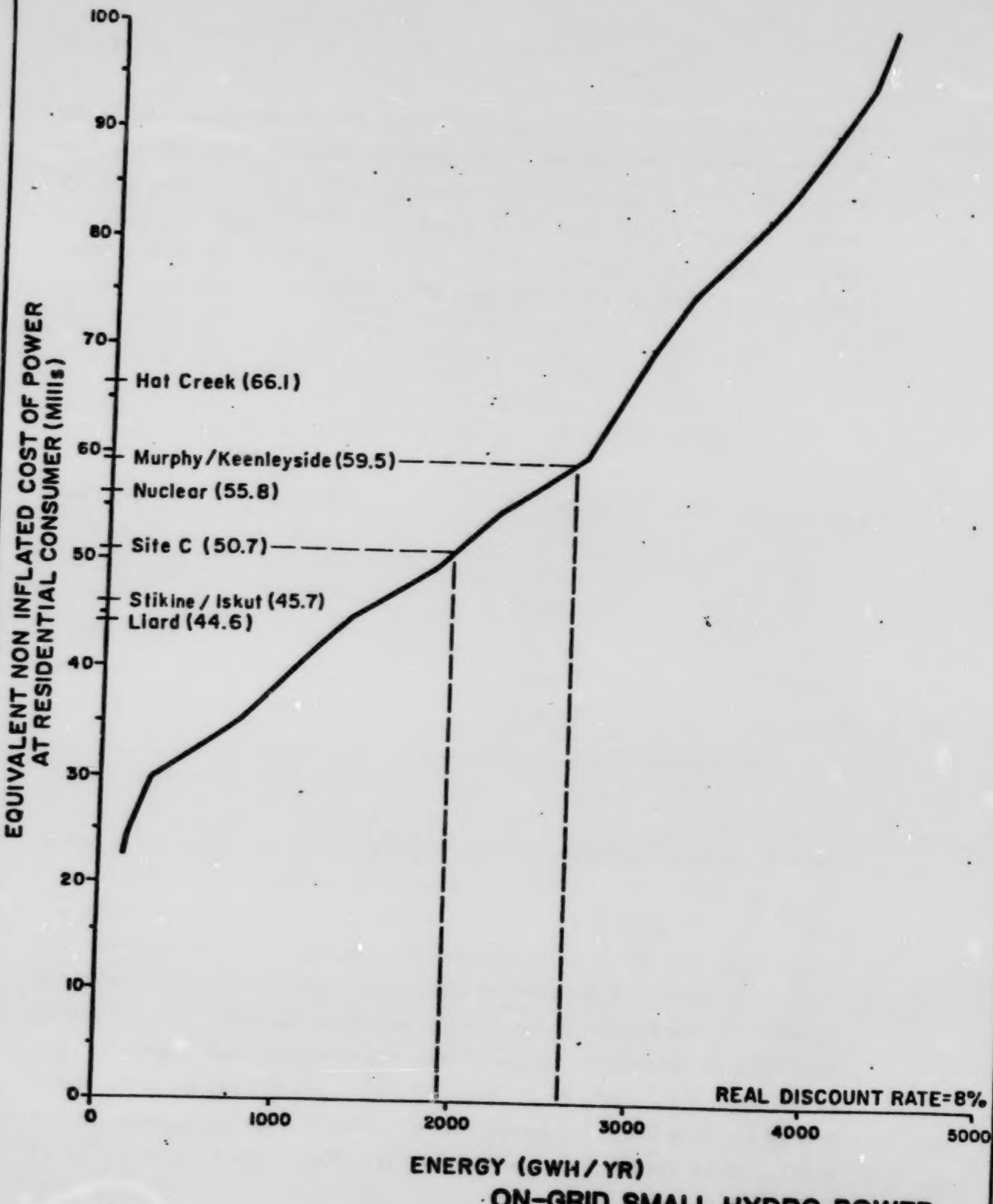
TABLE 2.1

CUMULATIVE INCREMENTAL ENERGY LOSS MULTIPLIERS

Voltage (kV)	100% Peak	75% Peak	50% Peak
500	1.0947	1.0747	1.0447
230	1.0933	1.0752	1.0490
138	1.1233	1.1087	1.0999
60	1.1128	1.0868	1.0660
Primary	1.3458	1.2199	1.1262
Secondary	1.6564	1.4279	1.2520

(Source B C Hydro - Reference 5)

The cost of energy from proposed conventional projects and small hydro power plants delivered to the final user at a secondary voltage level is presented in Figure 2.4. The generation costs of the conventional hydro power plants are adjusted by the 500 kV incremental loss multiplier to account for the transmission losses and the costs of small hydro power are adjusted by a factor to allow for losses in the primary and/or secondary network. When economic feasibility is defined in terms of the delivered cost of energy to the residential/general user, up to 80 small hydro power sites could be viable related to Peace Site C for a capability of 1,890 GW.h per year, and up to 123 sites could be viable related to Murphy Creek/Keenlyside for a capability of 2,570 GW.h per year.



ON-GRID SMALL HYDRO POWER
INCREMENTAL ENERGY CAPABILITY
vs. INCREMENTAL COST OF POWER
(At point of delivery to consumer)
FIGURE 2·4

It should be noted that in certain circumstances the methodology adopted here may overstate the potential savings in transmission losses possible for small hydro power development. This is because the potential savings not only depend on the voltage and length of the transmission line to which the small hydro power plant is being connected, but also on the total requirements of the users served. If it is the case that small hydro power production exceeds the requirements of downline users, then it would be necessary to transfer power back into the main grid. The small hydro power transmission loss savings would be much lower in this circumstance. Studies in the United States (Reference 8) have shown that these effects are site specific and have concluded that they should not be a consideration in setting power rates. Although the magnitude of the potential savings should be evaluated further in future studies, it may be the case that the lack of downline demand is not particularly significant in British Columbia. This is because many of the best small hydro power sites are in the Lower Mainland and Vancouver Island, near low voltage portions of the grid. In most cases there is ample downline demand to absorb all the power produced.

Average Costs of Small Hydro Power

If small hydro power were developed up to a long term marginal cost less than or equal to the economic cost of power from Peace Site C (35.5 mills), the average cost of the approximately 1370 GW.h per year of energy would be about 27 mills. This means that this much energy could be available at an average cost of about 8.5 mills less than that from Peace Site C.

In present value terms the value of substituting this low cost small hydro power for 2.3 years of operation of Peace Site C (around 1990 to 1992) is approximately $13 million.

Phased Small Hydro Power Development

The advantage of small hydro power relative to conventional projects in terms of scheduling new capacity to match load growth has not been captured in the analysis thus far. During periods of relatively modest load growth, limited export opportunities and conventional projects of large capacity, the number of economically feasible small hydro power sites increases because the economic cost of carrying large increments of unused capacity in the large hydro power facilities is significant.(1)

This is a complex area of energy planning that cannot be adequately covered in this study. Our purpose here is to illustrate the flexibility of small hydro power in meeting additional load growth, and the nature of the economic cost savings that could be realized. A more comprehensive approach would include an assessment of the BC Hydro generation plan to include the phased development of small hydro power and the cost of such a modified generation plan compared to the current one.

To illustrate the potential advantages of small hydro power development, a phased development program was compared to the construction of the Peace Site C plant to meet forecasted load growth (Figure 2.5). The incremental nature of the small hydro power resource is evident in this illustration as capacity is added to match expected load growth. The more efficient utilization of invested capital (assuming that a large proportion of the capacity of the larger project is not initially utilized) is a major potential cost saving. Potential cost savings also stem from two other sources. Some small hydro power capacity is less costly to develop than conventional hydro power (Figure 2.3 and Figure 2.4). Also, the major capital expenditures for small hydro power need not be committed until one to two years in advance of the in-service date. Peace Site C, on the other hand, requires a 9 year construction

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(1) A number of recent studies indicate that the demand for electricity exports on an interruptible basis will be limited (Reference 7). For example, the average cost of Site C was estimated on the assumption that its full energy production will be demanded as soon as it is technically available. If, on the other hand, production were constrained by the growth in provincial energy requirements, then the average cost would be 41.4 mills/kW.h (assuming MEMPR electricity forecasts). The difference in average cost of 5.9 mills is the incremental cost of carrying the unused capacity of the project until domestic requirements grow to the point it is fully utilized. This could be reduced if there were a demand for exported power at that time.

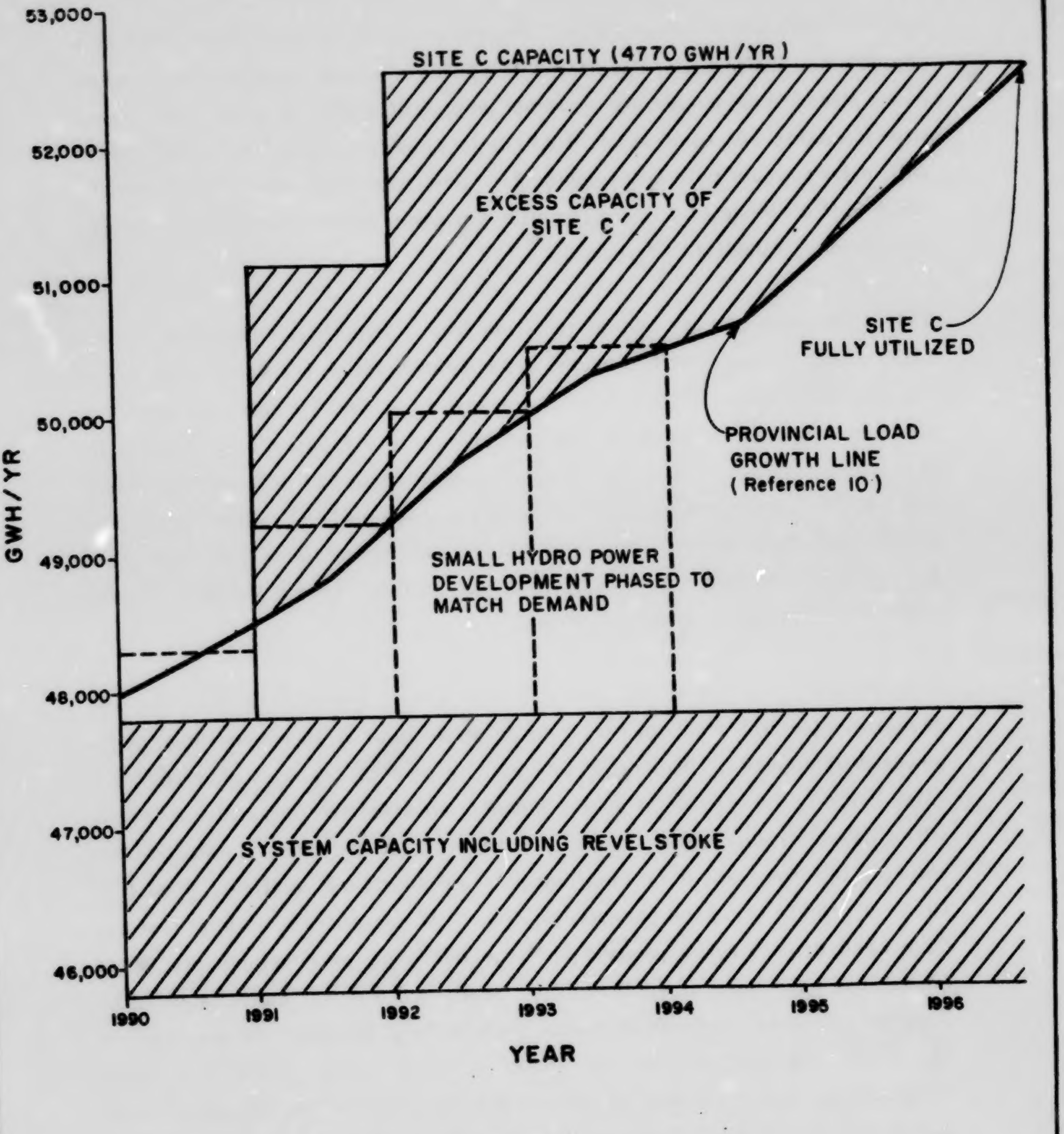

ILLUSTRATION OF PHASED SMALL HYDRO POWER DEVELOPMENT COMPARED TO SITE C IN MEETING PROJECTED ENERGY REQUIREMENT

FIGURE 2.5

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period. Therefore the Peace Site C Project could be deferred if preceded by a phased small hydro power development. However, as the less costly small hydro power sites are developed, the incremental cost of additional small hydro power sites increases. At some point, it will be less costly to meet future load growth with a large scale power development. Given the load growth projection by MEMPR (Reference 6), a phased small hydro power development could defer the conventional project 2 to 3 years.

The dollar value of cost savings resulting from a hypothetical delay of a large hydro power project that has excess capacity depends on the value of power in the export market. In the case of Peace Site C and assuming no export is possible, the present value of the approximately 2.3 year delay possible by developing feasible small hydro power, could be about $23 million on a present value basis. This, combined with the potential saving of $13 million due to less costly small hydro power, indicates a possible net present value benefit of about $36 million if the feasible small hydro power resource were developed between 1990 to 1993 in advance of Peace Site C.

This analysis is presented to illustrate the flexibility implicit in the development of the small hydro power resource relative to conventional hydro power developments. Projecting future requirements is always uncertain, but small hydro power may offer energy planners an effective response for dealing with this uncertainty. This flexibility arises from the incremental nature of the resource (a large number of small capacity sites) and the relatively short lead time required to bring the capacity on line. Although these beneficial features have been demonstrated relative to large hydro power developments, these advantages have general applicability. Small hydro power capacity could be developed to meet unforeseen circumstances (e.g. to assist in meeting the electricity requirements of new industry) or to serve attractive market opportunities well in advance of conventional hydro power developments. Even during periods of rapid load growth, when small hydro power would have a limited effect on the timing of large projects, the average cost of a significant number of sites is below the cost of a new conventional hydro power development, and could be brought into service much sooner.

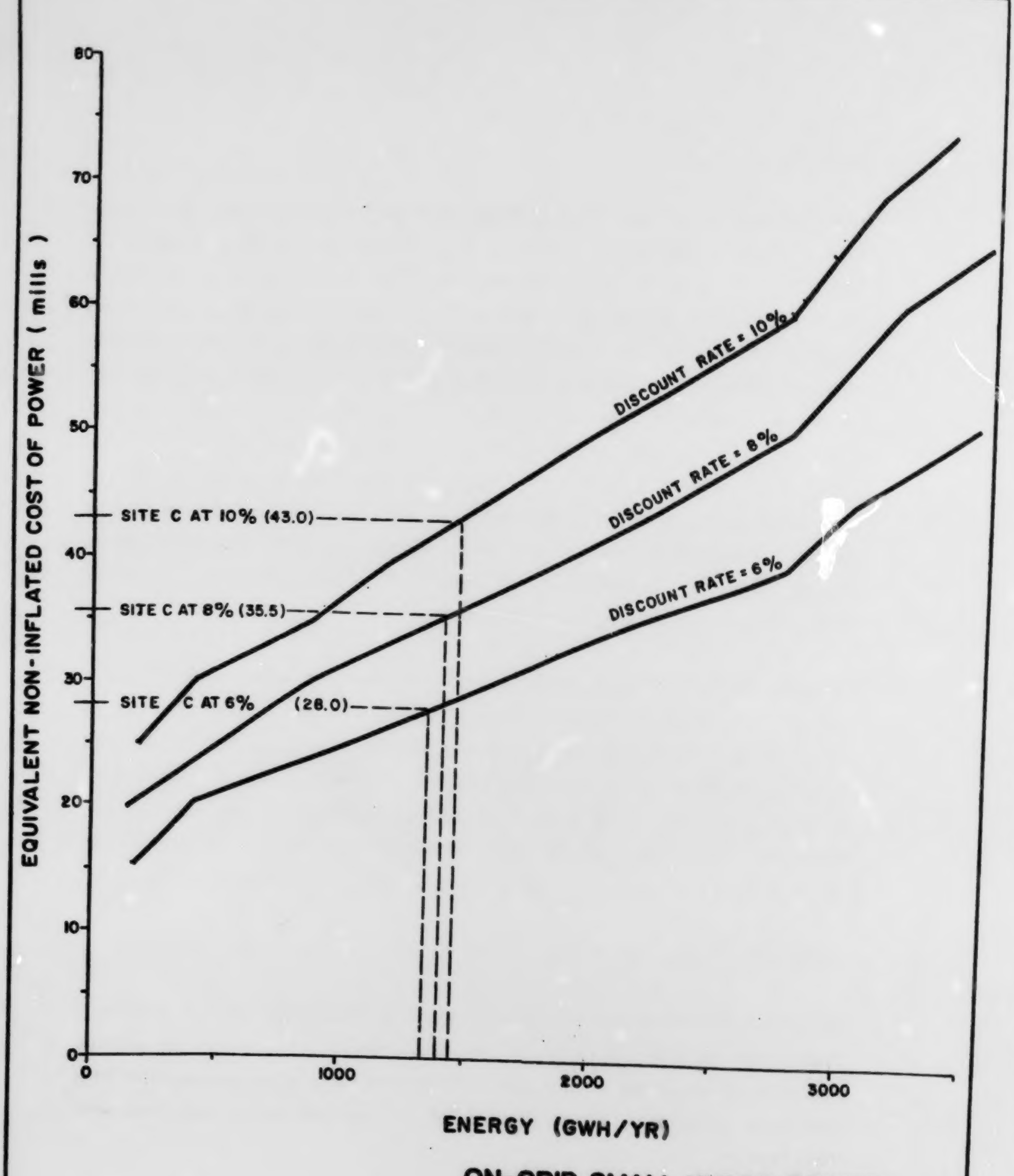
Summary

It is important to correctly interpret the findings of the above discussion in the light of the survey nature of the study. It cannot necessarily be concluded that the collection of small hydro power sites identified here as economically feasible, should affect the scheduling of Peace Site C or other major generation projects. Firstly, the evaluation is built up from preliminary cost estimates that were prepared according to accepted standards, but without the benefit of on-site information. Some of the sites included here may prove to be not technically developable. However, it is also likely that a number of feasible sites were overlooked, particularly low-head sites, sites requiring storage and other conditions impossible to identify on a map survey, and sites found in the **Resource Assessment** but omitted here because of insufficient information. Secondly, economic feasibility is only one consideration in assessing the overall desirability of small hydro power development.

Financial feasibility is assessed in Section 3. However, environmental, social and land use constraints must also be considered. Lastly, the logistics of acquiring the necessary approvals, and constructing a large number of sites in a relatively short period may be constraining. Nevertheless, it is correct to conclude that the small hydro power resource offers an economically attractive, essentially unexploited energy source which is worthy of consideration as a supplement to the energy reserve of British Columbia.

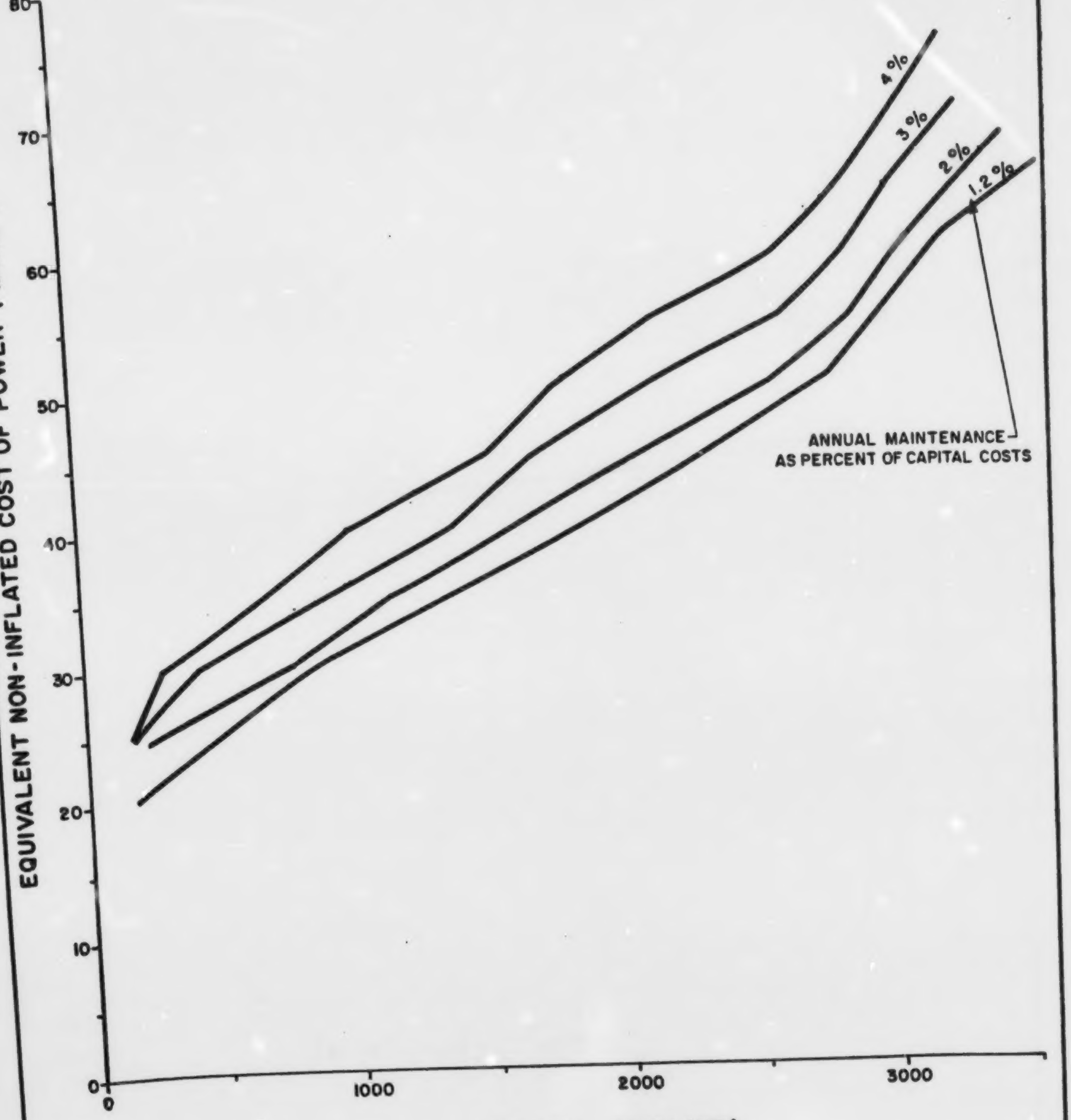
2.3 SENSITIVITY ANALYSIS

The most important factors influencing the conclusions of the economic analysis are the discount rate, the cost of operation and maintenance and the possibility of exporting surplus power during the early years of operation of a large scale hydro power plant, Figures 2-6, 2-7 and 2-8 respectively deal with these factors.



ON-GRID SMALL HYDRO POWER
INCREMENTAL ENERGY CAPABILITY
vs. INCREMENTAL COST OF POWER
(Sensitivity to discount rate)

FIGURE 2.6



ON-GRID SMALL HYDRO POWER
INCREMENTAL ENERGY CAPABILITY
vs. INCREMENTAL COST OF POWER
(Sensitivity to maintenance cost)
FIGURE 2.7

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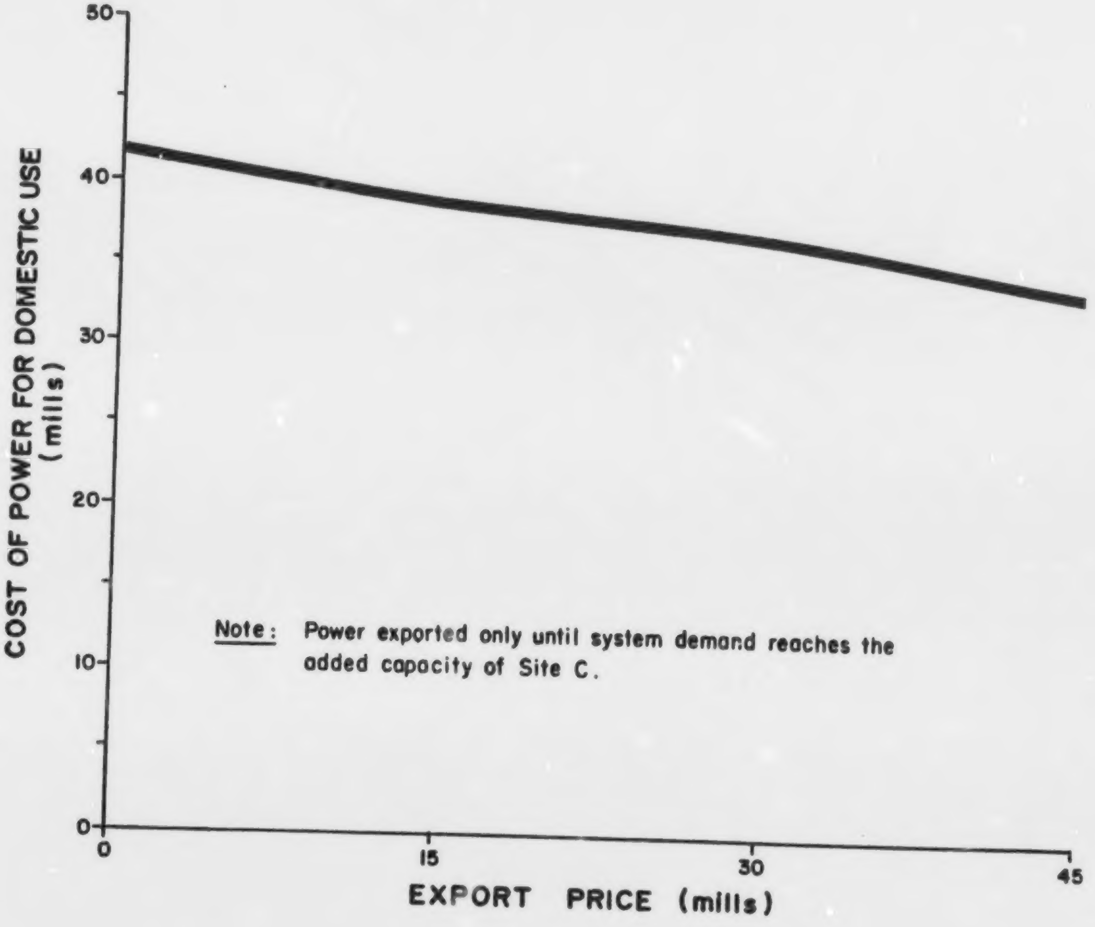

Note: Power exported only until system demand reaches the added capacity of Site C.

COST OF SITE C POWER vs. EXPORT PRICE

5276 DCS

FIGURE 2.8

Figure 2-6 illustrates that although the cost of power is sensitive to the discount rate, the relative costs between large and small hydro power is not strongly affected. However, there is a slight tendency for reduced relative cost of small hydro power at increasing discount rates because of its relatively shorter lead time and development period.

Figure 2-7 illustrates that the cost of small hydro power is sensitive to the level of operation and maintenance costs. At a cost level of 35 mills the quantity of feasible power drops from about 1300 GW.h/year to about 700 GW.h/year as the level of costs rises from 1.2 percent up to 4 percent of capital costs.

Figure 2-8 illustrates how the economic cost of power from Peace Site C is affected by the export price of surplus power. The cost drops from about 42 mills if no export market is available down to 34 mills if export of surplus power is possible at 45 mills. This cost range corresponds to an amount of on-grid feasible small hydro power ranging from about 2100 GW.h/year for no export down to about 1200 GW.h/year for an export price of 45 mills.

2.4 OFF-GRID APPLICATIONS

Presently, there are a number of communities, tourist facilities, camps (logging and mining), park facilities, military establishments, and other settlements that are isolated from the provincial transmission grid. Electricity (if it is available) is generally provided to these settlements by local diesel generating plants operated either privately or by BC Hydro. The off-grid small hydro power potential refers to the technically feasible sites identified in the **Resource Assessment** that could supplement diesel generation in those areas served by BC Hydro.

Off-grid small hydro power development would generally supply some portion of the base load for the system, with the diesel unit meeting the load swings; electricity requirements during insufficient stream flow conditions; and emergencies. It is in this manner that BC Hydro currently operates the mixed (diesel and hydro) system at Bella Coola. It would generally not be the case that small hydro power would totally replace existing diesel units (i.e. offer capital cost savings). Rather, the existing diesel capacity would still be required, but it would operate less frequently. Under these conditions, the quantifiable economic benefit of off-grid small hydro power development is the value of the diesel fuel displaced.

For off-grid applications, the development of a small hydro power site(s) must be tailored to the electricity demands of the settlement served. For on-grid application, where the plant size is unconstrained by system demand, the optimal plant capacity is typically near the average flow of the stream. This may not be the case for off-grid applications, since the system load might dictate a plant of smaller capacity. Hence the data required to assess the economic feasibility of off-grid applications are not available given the survey level of this study. The off-grid potential of the small hydro power resource located near the diesel generating areas operated by BC Hydro is considered below. The analysis focussed on these areas because the pertinent information regarding the operating characteristics of the system was readily available. The analysis should, however, be considered indicative, rather than conclusive, since more detailed data are required to make a final judgment regarding the economic feasibility of small hydro power serving these communities.

BC Hydro presently operates 13 remote diesel generating stations serving communities currently isolated from the provincial grid. The largest non-integrated community is Fort Nelson, which uses natural gas to power its generators. The remaining 12 communities are considerably smaller and rely on diesel fuel for power generation. The smallest in terms of fewest customers is Telegraph Creek, with a total of 69 customers and a total electricity demand in 1981/82 of only 1.014 GW.h. The cost of diesel generation in terms of mills per kilowatt hour of electricity produced ranged from a high of 158 at Telegraph Creek to a low of 90 at Bella Coola (Table 2.2 - 2 sheets).

In the **Resource Assessment**, small hydro power potential was identified near eight of the 13 communities. Hence, there are remote communities that have identified small hydro power potential that could be developed at an

Sheet 1 of 2

TABLE 2.2

SMALL HYDRO POWER POTENTIAL NEAR B C HYDRO DIESEL GRID AREAS

Location	Energy Demand (1982 GW.h)	Energy Cost(1) (Mills)	Potential Small Hydro Power Sites		
			Stream Name	Energy Output (GW.h/Year	Economic Cost(2) (Mills)
Anahim Lake	2.26	103	None	-	-
Atlin	2.38	162	Fourth of July Creek	3.1	222
			Hitchcock Creek	2.0	332
			Indian Creek	0.9	423
			Pine Creek Ditch	5.1	101
				11.1	
Bamfield	3.17	107	Handy Creek	14.6	35
			Macktush Creek	5.4	72
				20.0	
Bella Bella	7.57	122	None	-	-
Bella Coola	11.11	90	Cacoohtin Creek	14.7	28
			Clayton Falls Creek	16.5	37
			Thorsen Creek	19.9	50
			Snootli Creek	13.8	37
				64.9	
Dease Lake	2.80	252(3)	None	-	-
Eddontenajon	0.96	-	None	-	-
Masset	18.36	107	Lignite Creek	11.7	85
Sandspit	17.56	111	Sachs Creek	4.4	69
			Tlell River	2.7	225
			Haans Creek	3.7	206
			Unnamed Creek (at 53 08; 131 53)	1.6	219
				12.4	

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(1) Based on fuel, operation and maintenance costs only

(2) Computed as described in Appendix 2

(3) Includes administration costs not directly related to Dease Lake

TABLE 2.2

SMALL HYDRO POWER POTENTIAL NEAR B C HYDRO DIESEL GRID AREAS

Location	Energy Demand (1982 GW.h)	Energy Cost(1) (Mills)	Potential Small Hydro Power Sites		
			Stream Name	Energy Output (GW.h/Year	Economic Cost(2) (Mills)
Stewart	12.83	127	American Creek	16.0	71
			Bear River	5.3	38
			Blackstock Creek	7.6	138
			Cascade River	8.7	50
			Glacier Creek	6.1	73
			Mamat Creek	11.8	158
				55.0	
Telegraph Creek	1.01	158	Dodjatin Creek	2.7	113
			Eight Mile Creek	0.7	237
			Mess Creek	40.6	71
			Telegraph Creek	2.4	102
			Nine Mile Creek	1.2	192
				47.6	
Tatla Lake	0.95	147	Unnamed Creek (at 51 55; 124 44)	0.7	281
			Unnamed Creek (at 51 26; 124 45)	5.1	106
			Lincoln Creek	0.9	248
				6.7	
				229.4	

average cost that is less than the cost of diesel. These communities include Atlin, Bella Coola, Sandspit, Stewart, Tatla Lake, Telegraph Creek, and Bamfield. A total of 35 sites were identified that could potentially supply electricity at a lower average cost than diesel.

For most communities, the identified small hydro power potential is greatly in excess of the load requirements. For example, six potential small hydro power sites were identified around the settlement of Stewart. Four could be developed at an average cost of less than 127 mill/kW.h (the average cost of diesel) and provide an energy capability of nearly 36.1 GW.h/year. However, current load requirements are only in the order of 13 GW.h/yr. With further study, the most suitable site(s) could be identified and the plant capacity sized to the system requirements. With the exception of Sandspit, where only one attractive site has been identified, the remaining five communities are similar to the example of Stewart noted above.

Further work is required to assess the economic feasibility of off-grid applications for small hydro power development. This will require more detailed site assessment as well as defining the role of small hydro power in an integrated diesel/hydro system. In contrast to on-grid applications, where the incremental capacity does not appear to be required until the early 1990s, off-grid applications offer an immediate cost savings. The development of off-grid small hydro power could also provide additional operational experience from which the more intensive on-grid development could benefit.

3. FINANCIAL ASSESSMENT OF THE SMALL HYDRO POWER RESOURCE

In Section 2 the economic value of the small hydro power resource was established, leading to an assessment of the amount of potential capacity for which development may be encouraged. The criterion for economic feasibility of a site was taken to be whether it could provide lower cost energy than the large scale hydro power sites which are likely to be next in line to be developed as the provincial power load exceeds present committed capacity. On this basis it was concluded that at least 50 and up to 80 of the lowest cost, undeveloped small hydro power sites could be economically feasible. This represents an installed peak generating capacity of from 300 MW to 432 MW, or energy outputs of from 1370 GW.h/year to 1970 GW.h/year.

Optimal scheduling of the development of this power would ensure that there was adequate power available to meet provincial demand when load exceeds present capacity at some time in the future. Present forecasts indicate this will be in about 1990 when about 555 GW.h/year of energy will be needed, increasing to 1111 GW.h/year in 1991, and 1944 GW.h/year in 1992. If the economically feasible portion of the small hydro power resource were developed in a timely manner it could in effect meet provincial load growth for over two years.

The economic analysis however does not present a complete description of project feasibility, and the process by which these sites might be implemented must be considered primarily in terms of the actual factors that motivate or inhibit possible developers of small hydro power sites.

Small hydro power plants could be developed by either B C Hydro or a private developer. The motivation for B C Hydro to develop the small hydro power resource would be to provide firm energy at a lower cost than it could by alternative methods such as large scale hydro or thermal plants. The normal motivation for private developers would be the opportunity for profit. However the development of plants by private developers implies a policy whereby B C Hydro would buy power and distribute it, or whereby B C Hydro would wheel power to other purchasers.

In Section 3.1 the general factors influencing financial feasibility are described; then in Section 3.2 a financial analysis of a typical small hydro power development is presented, primarily from the perspective of a private developer. The objective is to analyze all cost, revenue and risk factors that a developer will experience, and thus to determine the sale price of power that must be achievable to make small hydro power projects attractive investments. This methodology is then applied to the inventory of actual sites as covered in Section 3.3. A long-run supply curve of small hydro power is derived that relates the quantity of power likely to be developed to the price level of power. This will appear similar to the economic supply curves in Section 2. However, it includes non-economic factors experienced by developers such as water rent, income tax, school tax and an increased discount rate due to higher sensitivity to risk.

3.1 FACTORS INFLUENCING FINANCIAL FEASIBILITY

The factors which influence the financial feasibility of a project include all those that could affect the revenues, costs, timing or uncertainties of the project; also all the economic factors discussed in the preceding chapter such as:

- capital costs of the plant;
- capital cost of transmission to the grid or location of use;
- operation and maintenance costs;
- management costs;
- transmission and downtime losses.

The developer of a small hydro power plant under existing legislation will experience the following additional costs which are real from his point of view but which do not directly represent economic costs:

Water Rent

Prior to the starting of operation of a small hydro power plant the holder of a water licence must pay a fee of \$0.50 per kW of licensed generating capacity. When the plant goes into operation the fee is \$2.50 per thousand kW.h of power generated plus $5.00 per kW of installed capacity. These rates are adjusted periodically and for the the purpose of this analysis have been assumed to escalate at the same rate as the price of electric power.

School Tax

Almost all real property and improvements in the province of British Columbia are liable for school tax. Small hydro power plants are assessable and taxable at rates established annually by regulation as provided by the Assessment Act and Schools Act. Assessments are based upon the current replacement cost for utility property, less depreciation allowances where applicable. Small hydro power plants are taxable on 35 percent of the actual value of assessable property. The 1982 weighted average mill rate was about 55 mills. School tax costs are assumed to escalate at the general inflation rate.

It is significant to note that the only properties specifically exempted from school tax are hydro power generating facilities on the Columbia River and Peace River. Since school taxes are one of the major operating costs of a small hydro power plant, the exemption of some large scale hydro power plants results in a distortion of the relative financial feasibility of these projects. This aspect is further discussed in Section 4 covering policy opportunities.

Utility Tax

B C Hydro pays annual grants to municipalities (and to the provincial government for rural areas), in lieu of the general municipal property taxes paid by private owners of real property. The tax is computed as 1 percent of electric revenues from annual sales within the boundaries of each municipality. This tax would not be directly charged to the owner/operator of a small hydro power facility, but would be paid by the agency distributing the power. Therefore, this tax has not been included in the financial analysis.

Project Financing

Hydro power developments are capital intensive, requiring relatively large capital expenditures followed by relatively small operating expenses after startup. This expenditure profile implies a declining net unit cost over the lifetime of a project. Furthermore, in the long run, the value of power can reasonably be expected to increase at a rate exceeding the general inflation rate. These factors create difficulties in the financing of hydro power projects by conventional level payment, declining balance loans. Nearly all hydro power projects (even if financially profitable on a net present value basis) show negative cash flows during early years followed by many years of expected large positive cash flows. Private developers of small hydro power projects are likely to be deterred by the initial years of negative cash flow even given the certainty of future profits.

Large utilities can overcome this problem through the use of revolving debt. For example, under instructions from the provincial government, BC Hydro is moving toward achieving a 130 percent coverage of gross debt interest where unamortized debt declines over the life of a project. This results in high initial power prices which decline over the life of a project.

A developer of a small hydro power project, however will probably not be able to obtain such a pricing schedule because his power must be priced at competititve rates immediately. An alternative would be to finance with a graduated payment loan linked to project net income so that positive cash flows are always obtained. This would result in an increasing principal balance in early years, which is repaid by increased payments in later years.

Such loan schemes are not likely to be available at present from the commercial financial markets without some form of government guarantee. As Section 3 deals with the financial feasibility of small hydro power projects under current conditions, the analysis will be based on conventional financing only. Innovative financing schemes as well as other alternatives for overcoming the problem of early negative cash flows will be dealt with more fully in Section 4.

Income Tax

Income tax is the most difficult factor to interpret in determining the general financial feasibility of the small hydro power resource. This is because different types of project developers may be taxed in different ways, ranging from utilities which pay no income tax, to individuals and corporations which are subject to full tax liability. The federal government has introduced an accelerated depreciation (capital cost allowance) scheme for tax purposes which permits private investors to depreciate the investment in three years (25%, 50%, 25% respectively) (Reference 11). The resulting tax losses in the early years can result in tax savings on other income which could be a substantial encouragement to private investors with taxable income from other sources. Note that accelerated depreciation will be of little value to investors with no other income to shelter. This accelerated capital cost allowance option is due to expire in 1985. If not renewed it will probably be replaced by the conventional capital cost allowance rate of 6 percent for these types of facilities. Financial analysis will be carried out for both types of capital cost allowance, but recommendations will be based on the conventional rate because most small hydro power development is likely to occur after 1985.

These factors make it impossible to produce generalized statements about the financial feasibility of small hydro power for all investors. The approach here will be to analyze feasibility for the following typical types of investors:

- investors who pay no income tax (for example, utilities);
- investors who only have income from the project itself (investors who cannot take advantage of the tax shelter afforded by the accelerated tax write off);
- investors who have other income which can be sheltered by tax losses from a project.

In the latter two cases a 50 percent marginal income tax rate was assumed.

Required Rate of Return

The economic evaluation presented in Section 3 used an 8 percent discount rate for evaluating future benefits which is equivalent to providing an 8 percent internal rate of return on capital. This discount rate is applicable to projects from the viewpoint of the entire province of British Columbia which is presumably so large that the risks and uncertainties of any given project are insignificant. However, a developer contemplating a single project will be more sensitive to risks and would require a higher rate of return as compensation. Such risks may also make it more difficult to obtain financing at a favourable rate. For the purpose of this analysis a risk premium of one per cent over the social discount rate has been assumed as a base case which results in a real rate of return of 9 percent or a nominal rate of return of 15 percent, assuming a rate of inflation of 7 percent. This is somewhat optimistic for the first small hydro power plants to be developed because they will be unfamiliar to investors. Therefore the first few plants may have to yield a higher return, perhaps 19 percent nominal, but the required yield should decline as the projects become familiar as investments. The first few investors will also likely be involved in the more attractive sites and thus a higher return should be readily available.

Factors which affect the uncertainty perceived by a developer will affect his required rate of return, and thus can affect the financial feasibility of a project. Therefore factors such as uncertainty of stream flows, capital costs and operating costs will increase the rate of return required by the developer. Other risk-related factors are more controllable by the appropriate government policies including uncertainty about the approval of a water licence, the ability to sell power and the sale price of power. The options and benefits of controlling risk will be discussed further in Section 4.

3.2 FINANCIAL FEASIBILITY ANALYSIS OF A TYPICAL PROJECT

Two computer models were developed to aid in the financial analysis of small hydro power sites. One model produces a detailed financial analysis of a site by forecasting all cash flows and determining the present value and internal rate of return given the sale price of power. The other model carried out a reverse analysis whereby the price of power necessary to achieve a given rate of return is calculated given the costs and other assumptions about a site.

The first model was used to produce Tables 3.1, 3.2 and 3.3 which illustrate the financial feasibility analysis of a typical small hydro power project. The analysis is for Perketts Creek which was ranked as the 15th best site out of all 521 on-grid sites for which cost analysis was done in the **Resource Assessment**. Table 3.1 outlines the input parameters which include the following:

Peak power output (installed capacity) of 4500 kW
Total plant capital cost of $5,436,000
Firmness factor of 55 percent
Discount rate of 15 percent
Power inflation rate of 7 percent
General inflation rate of 6 percent
Conventional debt at 80 percent of costs at a 12 percent interest rate
Income tax rate of 50 percent
Capital cost allowance of 6 percent per year
Power sales at 35 mills

Table 3.2 shows the cash flows during the two year construction period. Equity and management fees are assumed to go into the project in proportion to hard costs. Hard costs are assumed to be incurred at an increasing rate as the year of completion is approached.

Table 3.3 shows the overall cash flows during the 50 year life of the project. Income from power sales is assumed to start in the year after completion of construction at which time it is $781,900, and to escalate thereafter. The net income of $510,900 in the first year is determined by deducting operation and maintenance costs ($73,300 in the first year), water rent ($80,100), and school tax ($117,600). All these costs escalate during the life of the project. Loan payments of $639,000 start in the first year of operation and continue during the assumed amortization period of 30 years.

TABLE 3.1 - SAMPLE INPUTS TO SMALL HYDRO FINANCIAL ANALYSIS MODEL

(Based on Perketts Creek)

```
PEAK POWER OUTPUT (KW)                   4,500
ENERGY OUTPUT (GWH/YR)                    19.5
HARD COST OF PLANT ($1000)             4,536.0
HARD COST OF TRNSMISSION ($1000)         900.0
TOTAL HARD CAPITAL COST ($1000)        5,436.0
FIRMNESS FACTOR (%)                       55.0

START YEAR                                1982
HORIZON (YRS OF OPERATION)                50.0
DOWNTIME & XMISSION LOSSES (%)            10.0
DESIRED RATE OF RETURN (%)                15.0
POWER INFLATION RATE (%)                   7.0
GENERAL INFLATION RATE (%)                 6.0
1ST YR. O & M (TRANSMISSION)               1.2 PERCENT OF CAPITAL COSTS
1ST YR. O & M (GENERATION)                 1.2 PERCENT OF CAPITAL COSTS
AVERAGE ASSET LIFE (YEARS)               1,000
EQUITY (% OF DEVEL. COST)                 20.0
LOAN AMOUNT (SEE AT RIGHT)             5,147.3
EQUITY AMOUNT (SEE AT RIGHT)           1,286.8
DEBT INTEREST RATE (%)                    12.0
AMORTIZATION PERIOD (YEARS)               30.0
LOAN PAYMENT ($1000)                     639.0
INCOME TAX RATE (%)                       50.0
ASSESSMENT RATIO (%)                      35.0
UTILITY TAX RATE (% OF POWER)              0.0
MEAN XMISSION LOSS TO USER (%)             9.0
MEAN SYSTEM MILL RATE                     31.5
SCHOOL TAX RATE (MILLS)                   55.0
WATER RENT:
   ON ENERGY PRODUCED                     2.50  DOLLARS PER 1000 KW/YEAR
   ON INSTALLED CAPACITY
      DURING CONSTRUCTION                 0.50  DOLLARS PER KWH OF CAPACITY/YEAR
      DURING OPERATION                    5.00  DOLLARS PER KWH OF CAPACITY/YEAR
CONSTRUCTION INTEREST RATE (%)            14.0
DEVELOPMENT PERIOD (YEARS)                   2
MANAG. FEE (% OF CAPITAL COST)             8.0

CAPITAL COST ALLOWANCE (%)                 6.0 (ENTER -1 FOR ACCELERATED RATE)
DEBT COVERAGE RATIO                      -1.00 (ENTER -1 FOR NO DEBT PAYMENT CEILING)

UNINTERRUPTABLE POWER:
   SALE PRICE (MILLS)                      0.0
   PERCENT OF TOTAL POWER                  0.0
INTERRUPTIBLE POWER:
   SALE PRICE (MILLS)                     35.0
   PERCENT OF TOTAL POWER                100.0
```

TABLE 3.2 - ANALYSIS OF DEVELOPMENT PERIOD AND OVERALL RATE OF RETURN FROM SMALL HYDRO FINANCIAL ANALYSIS MODEL

(Based on Perketts Creek)

DEVELOPMENT PERIOD

YEAR	CONSTRUCTION COST	MANAGEMENT COST	EQUITY DURING CONSTRUCTION	INTEREST COST	CUMULATIVE DEBT	CUMULATIVE COST	LONG TERM LOAN DRAW	TOTAL EQUITY
1982	1,812.0	145.0	391.4	109.6	1,675.2	2,066.5	0.0	391.4
1983	3,624.0	289.9	782.8	453.7	5,260.0	6,434.2	5,147.3	895.4
1984	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1985	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1986	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1987	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1988	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	5,436.0	434.9	1,174.2	563.3	5,260.0	6,434.2	5,147.3	1,286.8

PRESENT VALUES AND RATES OF RETURN

PRESENT VALUE BEFORE INCOME TAX	766.6
PRESENT VALUE AFTER INCOME TAX	423.4
IRR AFTER INCOME TAX	17.7

TABLE 3.3 - CASH FLOWS DURING OPERATIONAL PERIOD FROM SMALL HYDRO

YEAR	POWER VALUE INTERRUP.	POWER VALUE UNINTERRUP.	POWER VALUE TOTAL	OPERATION AND MAINTENANCE	WATER RENT	SCHOOL TAX	UTILITY TAX	NET INCOME	TOTAL LOAN PAYMENT	PRINCIPAL BALANCE (YR END)	INTEREST PAYMENT	EQUITY INFLOW	BEFORE TAX CASH FLOW	UNDEPREC. BALANCE (YR END)	CAPITAL COST ALLOWANCE	TAXABLE INCOME	TAX PAYABLE	AFTER TAX CASH FLOW
1982	0.0	0.0	0.0	0.0	2.3	0.0	0.0	-2.3	0.0	0.0	0.0	391.4	-393.7	0.0	0.0	-2.3	-1.1	-392.5
1983	0.0	0.0	0.0	0.0	2.4	0.0	0.0	-2.4	0.0	5,147.3	0.0	495.4	-497.8	6,434.2	0.0	-2.4	-1.2	-496.6
1984	781.9	0.0	781.9	73.3	80.1	117.6	0.0	510.9	639.0	5,126.0	617.7	0.0	-128.1	6,048.1	386.1	-492.9	-246.4	118.3
1985	836.6	0.0	836.6	77.7	84.9	124.5	0.0	549.5	639.0	5,102.1	615.1	0.0	-89.5	5,685.2	362.9	-428.5	-214.2	124.8
1986	895.2	0.0	895.2	82.4	90.0	131.8	0.0	591.0	639.0	5,075.4	612.3	0.0	-48.0	5,344.1	341.1	-363.3	-181.7	133.7
1987	957.9	0.0	957.9	87.3	95.4	139.6	0.0	635.6	639.0	5,045.4	609.0	0.0	-3.4	5,023.5	320.6	-294.1	-147.1	143.6
1988	1,024.9	0.0	1,024.9	92.5	101.1	147.9	0.0	683.4	639.0	5,011.8	605.4	0.0	44.4	4,722.1	301.4	-223.4	-111.7	156.1
1989	1,096.7	0.0	1,096.7	98.1	107.2	156.6	0.0	734.8	639.0	4,974.2	601.4	0.0	95.8	4,438.7	283.3	-149.9	-74.9	170.8
1990	1,173.4	0.0	1,173.4	104.0	113.6	165.8	0.0	790.1	639.0	4,932.2	596.9	0.0	151.1	4,172.4	266.3	-73.2	-36.6	187.6
1991	1,255.6	0.0	1,255.6	110.2	120.4	175.6	0.0	849.4	639.0	4,885.0	591.9	0.0	210.4	3,922.1	250.3	7.2	3.6	206.8
1992	1,343.5	0.0	1,343.5	116.8	127.7	185.9	0.0	913.1	639.0	4,832.2	586.2	0.0	274.1	3,686.7	235.3	91.6	45.8	228.3
1993	1,437.5	0.0	1,437.5	123.8	135.3	196.9	0.0	981.5	639.0	4,773.0	579.9	0.0	342.5	3,465.5	221.2	180.4	90.2	252.3
1994	1,538.1	0.0	1,538.1	131.3	143.4	208.5	0.0	1,055.0	639.0	4,706.8	572.8	0.0	416.0	3,257.6	207.9	274.3	137.1	278.8
1995	1,645.8	0.0	1,645.8	139.1	152.0	220.7	0.0	1,133.9	639.0	4,632.6	564.8	0.0	494.9	3,062.2	195.5	373.6	186.8	308.1
1996	1,761.0	0.0	1,761.0	147.5	161.2	233.7	0.0	1,218.6	639.0	4,549.5	555.9	0.0	579.6	2,878.4	183.7	479.0	239.5	340.1
1997	1,884.3	0.0	1,884.3	156.3	170.8	247.5	0.0	1,309.6	639.0	4,456.4	545.9	0.0	670.6	2,705.7	172.7	591.0	295.5	375.1
1998	2,016.2	0.0	2,016.2	165.7	181.1	262.1	0.0	1,407.3	639.0	4,352.2	534.8	0.0	768.3	2,543.4	162.3	710.2	355.1	413.2
1999	2,157.3	0.0	2,157.3	175.7	191.9	277.6	0.0	1,512.2	639.0	4,235.5	522.3	0.0	873.2	2,390.8	152.6	837.3	418.6	454.5
2000	2,308.3	0.0	2,308.3	186.2	203.5	293.9	0.0	1,624.8	639.0	4,104.7	508.3	0.0	985.8	2,247.3	143.4	973.1	486.5	499.2
2001	2,469.9	0.0	2,469.9	197.4	215.7	311.2	0.0	1,745.6	639.0	3,958.3	492.6	0.0	1,106.6	2,112.5	134.8	1,118.2	559.1	547.5
2002	2,642.8	0.0	2,642.8	209.2	228.6	329.6	0.0	1,875.4	639.0	3,794.2	475.0	0.0	1,236.4	1,985.7	126.7	1,273.7	636.8	599.6
2003	2,827.8	0.0	2,827.8	221.8	242.3	349.0	0.0	2,014.7	639.0	3,610.5	455.3	0.0	1,375.7	1,866.6	119.1	1,440.3	720.1	655.6
2004	3,025.7	0.0	3,025.7	235.1	256.9	369.5	0.0	2,164.3	639.0	3,404.8	433.3	0.0	1,525.3	1,754.6	112.0	1,619.0	809.5	715.8
2005	3,237.6	0.0	3,237.6	249.2	272.3	391.3	0.0	2,324.8	639.0	3,174.4	408.6	0.0	1,685.8	1,649.3	105.3	1,810.9	905.5	780.3
2006	3,464.2	0.0	3,464.2	264.1	288.6	414.4	0.0	2,497.1	639.0	2,916.3	380.9	0.0	1,858.1	1,550.4	99.0	2,017.2	1,008.6	849.5
2007	3,706.7	0.0	3,706.7	280.0	305.9	438.8	0.0	2,682.0	639.0	2,627.2	350.0	0.0	2,043.0	1,457.3	93.0	2,239.0	1,119.5	923.5
2008	3,966.1	0.0	3,966.1	296.8	324.3	464.6	0.0	2,880.4	639.0	2,303.5	315.3	0.0	2,241.4	1,369.9	87.4	2,477.7	1,238.9	1,002.6
2009	4,243.8	0.0	4,243.8	314.6	343.7	492.0	0.0	3,093.4	639.0	1,940.9	276.4	0.0	2,454.4	1,287.7	82.2	2,734.8	1,367.4	1,087.0
2010	4,540.8	0.0	4,540.8	333.4	364.4	521.0	0.0	3,322.0	639.0	1,534.8	232.9	0.0	2,683.0	1,210.4	77.3	3,011.9	1,505.9	1,177.1
2011	4,858.7	0.0	4,858.7	353.5	386.2	551.7	0.0	3,567.3	639.0	1,080.0	184.2	0.0	2,928.3	1,137.8	72.6	3,310.5	1,655.3	1,273.1
2012	5,198.8	0.0	5,198.8	374.7	409.4	584.2	0.0	3,830.5	639.0	570.5	129.6	0.0	3,191.5	1,069.5	68.3	3,632.7	1,816.3	1,375.2
2013	5,562.7	0.0	5,562.7	397.1	434.0	618.6	0.0	4,113.0	639.0	0.0	68.5	0.0	3,474.0	1,005.4	64.2	3,980.4	1,990.2	1,483.8
2014	5,952.1	0.0	5,952.1	421.0	460.0	655.0	0.0	4,416.1	0.0	0.0	0.0	0.0	4,416.1	945.1	60.3	4,355.8	2,177.9	2,238.2
2015	6,368.8	0.0	6,368.8	446.2	487.6	693.6	0.0	4,741.3	0.0	0.0	0.0	0.0	4,741.3	888.3	56.7	4,684.6	2,342.3	2,399.0
2016	6,814.6	0.0	6,814.6	473.0	516.9	734.5	0.0	5,090.2	0.0	0.0	0.0	0.0	5,090.2	835.0	53.3	5,036.9	2,518.5	2,571.8
2017	7,291.6	0.0	7,291.6	501.4	547.9	777.8	0.0	5,464.6	0.0	0.0	0.0	0.0	5,464.6	784.9	50.1	5,414.5	2,707.2	2,757.3
2018	7,802.0	0.0	7,802.0	531.5	580.8	823.6	0.0	5,866.2	0.0	0.0	0.0	0.0	5,866.2	737.8	47.1	5,819.1	2,909.6	2,956.7
2019	8,348.1	0.0	8,348.1	563.3	615.6	872.1	0.0	6,297.1	0.0	0.0	0.0	0.0	6,297.1	693.6	44.3	6,252.8	3,126.4	3,170.7
2020	8,932.5	0.0	8,932.5	597.2	652.5	923.4	0.0	6,759.4	0.0	0.0	0.0	0.0	6,759.4	652.0	41.6	6,717.8	3,358.9	3,400.5
2021	9,557.8	0.0	9,557.8	633.0	691.7	977.8	0.0	7,255.3	0.0	0.0	0.0	0.0	7,255.3	612.9	39.1	7,216.2	3,608.1	3,647.2
2022	10,226.8	0.0	10,226.8	671.0	733.2	1,035.4	0.0	7,787.3	0.0	0.0	0.0	0.0	7,787.3	576.1	36.8	7,750.5	3,875.2	3,912.1
2023	10,942.7	0.0	10,942.7	711.2	777.2	1,096.4	0.0	8,357.9	0.0	0.0	0.0	0.0	8,357.9	541.5	34.6	8,323.3	4,161.7	4,196.2
2024	11,708.7	0.0	11,708.7	753.9	823.8	1,161.0	0.0	8,970.0	0.0	0.0	0.0	0.0	8,970.0	509.0	32.5	8,937.5	4,468.8	4,501.2
2025	12,528.3	0.0	12,528.3	799.1	873.2	1,229.4	0.0	9,626.6	0.0	0.0	0.0	0.0	9,626.6	478.5	30.5	9,596.0	4,798.0	4,828.6
2026	13,405.3	0.0	13,405.3	847.1	925.6	1,301.8	0.0	10,330.8	0.0	0.0	0.0	0.0	10,330.8	449.8	28.7	10,302.1	5,151.1	5,179.8
2027	14,343.7	0.0	14,343.7	897.9	981.2	1,378.5	0.0	11,086.2	0.0	0.0	0.0	0.0	11,086.2	422.8	27.0	11,059.2	5,529.6	5,556.6
2028	15,347.7	0.0	15,347.7	951.8	1,040.0	1,459.6	0.0	11,896.3	0.0	0.0	0.0	0.0	11,896.3	397.4	25.4	11,870.9	5,935.5	5,960.8
2029	16,422.1	0.0	16,422.1	1,008.9	1,102.4	1,545.6	0.0	12,765.2	0.0	0.0	0.0	0.0	12,765.2	373.6	23.8	12,741.3	6,370.7	6,394.5
2030	17,571.6	0.0	17,571.6	1,069.4	1,168.6	1,636.6	0.0	13,697.0	0.0	0.0	0.0	0.0	13,697.0	351.2	22.4	13,674.6	6,837.3	6,859.7
2031	18,801.6	0.0	18,801.6	1,133.6	1,238.7	1,733.0	0.0	14,696.4	0.0	0.0	0.0	0.0	14,696.4	330.1	21.1	14,675.3	7,337.6	7,358.8
2032	20,117.7	0.0	20,117.7	1,201.6	1,313.0	1,835.0	0.0	15,768.1	0.0	0.0	0.0	0.0	15,768.1	310.3	19.8	15,748.3	7,874.1	7,893.9
2033	21,526.0	0.0	21,526.0	1,273.7	1,391.8	1,943.1	0.0	16,917.4	0.0	0.0	0.0	0.0	16,917.4	291.7	18.6	16,898.8	8,449.4	8,468.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	7 189.6	0.0	7 189.6	447.3	445.2	980.4	0.0	4 950.6	3 172.6		2 939.1	887.4	768.6		1 309.0	690.6	345.2	423.6

The before-tax cashflow is calculated by deducting the loan payment from the net income. It can be seen that negative before-tax flows are experienced for the first four years of operation because of the use of conventional debt financing. Taxable income is calculated by deducting loan interest and the capital cost allowance from net income. Capital cost allowance is based on the normal six percent declining balance method. This results in availability of a tax shelter for other income resulting in negative tax being payable during the early years. This means tax savings on other income. In the example it can be seen that the tax sheltering effect is maximum in the first year of operation at which time it has a value of $492,800. Thus the after-tax cash flow is positive during the early years of operation because of the assumed tax savings on other income. However these tax shelter benefits would only be available to a developer who has as considerable other taxable income as the available tax shelter in a given year.

It is possible to determine the relative significance of these factors by comparing them on a net present value basis over the life of the project (Table 3-4). It can be seen that school taxes are the largest expense (13.3 percent of gross income). Water rent and operation and maintenance are smaller and of about equal magnitude (9.3 percent and 8.4 percent respectively).

If the accelerated capital cost allowance method had been used then the CCA deduction would have been $1,609,000 in the first year, $3,216,000 in the second year, $1,609,000 in the third year and zero thereafter. This would have resulted in large tax losses being available to shelter other income.

TABLE 3 - 4

NET PRESENT VALUES OF COSTS AND REVENUE ITEMS OVER THE LIFE OF A TYPICAL SMALL HYDRO POWER PROJECT

(Discount Rate of 15%)

	Item	Net Present Value ($1,000)	Percent of Gross Income	Calculation
(1)	Gross Income from Power Sales	7,190	100	-
(2)	Operation and Maintenance Costs	605	8.4	-
(3)	Water Rent	665	9.3	-
(4)	School Tax	960	13.3	-
(5)	Net Income	4,959	69.0	(1)-(2)-(3)-(4)
(6)	Total Loan Payment	3,173	44.1	-
(7)	Interest Payment	2,878	40.0	-
(8)	Equity	1,017	14.1	-
(9)	Before Tax Cash Flow	769	10.7	(5)-(6)-(8)
(10)	Capital Cost Allowance	1,390	19.3	-
(11)	Taxable Income	690	9.6	(5)-(7)-(10)
(12)	Tax Payable	345	4.8	0.5 x (11)
(13)	After Tax Cash Flow	423	5.9	(9) - (12)

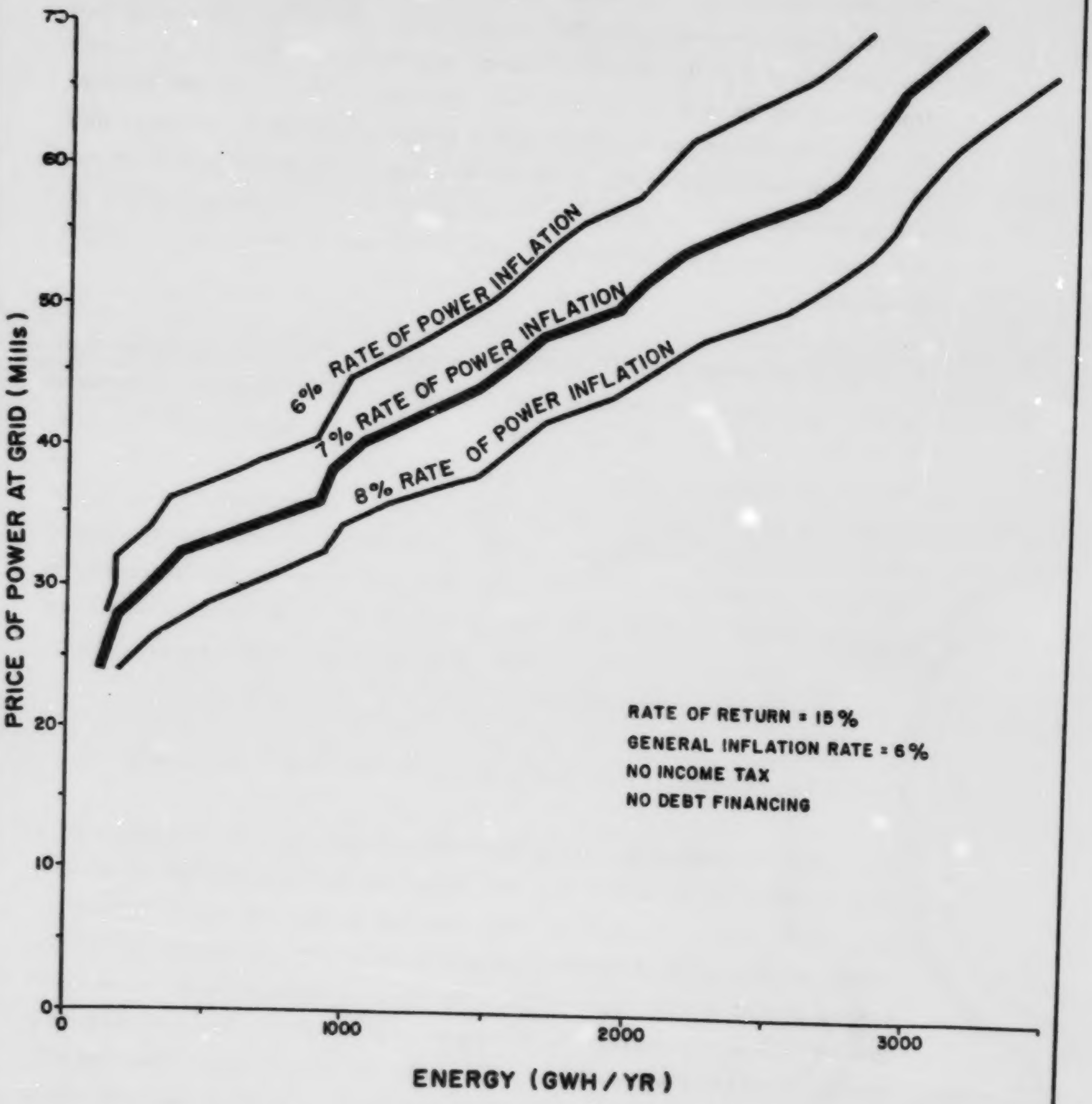
The same basic methodology applies to any small hydro power site, whether on-grid or off-grid. It is assumed that on-grid plants can sell all the energy that they produce so that the amount of energy supplied can be determined directly from the plant generating capacity and firmness factor. Also, the price of power will be dictated by B C Hydro unless wheeling is allowed. This price may or may not be related to the incremental value of the power to B C Hydro. During the course of the study, no formal definitive policy was available from B C Hydro covering the purchase of power from private developers in British Columbia.

The price of power for off-grid sites is given by the opportunity cost of generating the power by the next best alternative method. In most cases this is by diesel generation which can indicate power values in the order of 100 mills. Another consideration which is more important for off-grid sites is that the demand for power may not match the availability. The appropriate load factor must be determined by detailed analysis of stream flow versus power demand during the day and throughout the year. The load factor will never exceed the firmness factor. In general, the high opportunity value of power makes more likely the financial feasibility of small hydro power for off-grid use even though load factors may be relatively low.

3.3 FINANCIAL FEASIBILITY OF THE SMALL HYDRO POWER RESOURCE

Given that the preceding type of analysis can determine the feasibility of a given small hydro project, it remains to be seen how the quantity of feasible small hydro power depends on the price of power and other factors, or conversely, the price of power necessary to encourage the development of the desired amount of small hydro power. As the price level of power increases in real terms it will be feasible to develop more power sites. This analysis is only relevant for sites that could be connected to the integrated grid because off-grid projects are too site-specific to deal with at a single assumed price. Therefore, the following analysis will only deal with on-grid sites.

The introduction to this Section indicated an objective of determining the quantity of power which is feasible to develop at various price levels. In this



ON-GRID SMALL HYDRO POWER
QUANTITY OF FINANCIALLY FEASIBLE POWER
vs. PRICE OF POWER

FIGURE 3.1

[illegible] DCS

study we have used the Peace Site C Project as the reference for determining economically feasible power (about 1370 GW.h/year of energy). In fact it is difficult to give a definitive answer because financial feasibility is highly sensitive to factors such as the growth rate of power prices, the target rate of return, the income tax rate of the developer, the availability of other income to use tax shelter benefits and many other factors.

Table 3.5 illustrates this problem. It was calculated using a computer program which determines the necessary power price to provide a given rate of return. The program determines the necessary price for each of the 521 potential on-grid sites and tabulates the amount of energy available at each increment of price level. It can be seen that assuming no tax costs or benefits and no debt financing, the quantity of feasible power at a price of 35 mills rises from 282 GW.h/year to 930 GW.h/year as the inflation rate of power rises from 6 percent to 8 percent. Similarly, for 7 percent power price inflation the quantity of feasible power rises from 129 GW.h/year to 590 GW.h/year as the price of power rises from 25 mills to 35 mills. Similar sensitivity can be seen when income tax and/or debt financing are assumed. In the after-tax cases the significant benefit of the accelerated write-off is clear. The most useful case on which to base a determination of the necessary price for a given amount of feasible power is the no tax/no debt case (Figure 3.1). This is because cases which assume debt are based on conventional debt financing which, as described above, results in years of negative cashflows which would probably not be acceptable to a developer. Any assumption of tax without debt financing is unduly pessimistic because the tax deductibility of interest is an important benefit in debt financing which in effect reduces the interest rate by up to 50 percent. It can be seen that the assumption of taxes, accelerated depreciation and debt financing results in the possible feasibility of large amounts of power at reasonable prices. In fact more power could be feasible than would be economically desirable. As stated above, conclusions should not be based on debt scenarios which are unrealistic. However, it is likely that if a modified graduated payment financing scheme can be found, it might have benefits which are intermediate between the tax/no debt and tax/conventional debt scenarios shown in Table 3.5. This is discussed further in Section 4.

TABLE 3.5
FINANCIAL FEASIBILITY OF ON-GRID POWER
(Quantity of Energy in GW.h per year)

Assumptions				Price of Power at Grid (Mills)						
Income Tax Payable	CCA	Debt	Power Inflation	20	25	30	35	40	45	50
No	N/A	No	6%	0	0	170	282	590	930	1,337
No	N/A	No	7%	0	129	170	590	930	1,451	1,763
No	N/A	No	8%	0	170	547	930	1,506	1,960	2,381
No	N/A	Yes	6%	0	0	170	412	870	1,165	1,610
No	N/A	Yes	7%	0	170	332	870	1,227	1,610	2,085
No	N/A	Yes	8%	0	282	870	1,249	1,659	2,156	2,721
Yes	6%	No	6%	0	0	0	0	0	170	170
Yes	6%	No	7%	0	0	0	0	170	170	412
Yes	6%	No	8%	0	0	0	170	282	432	870
Yes	Accel.	No	6%	0	0	0	170	170	412	870
Yes	Accel.	No	7%	0	0	129	170	432	870	1,115
Yes	Accel.	No	8%	0	0	170	446	892	1,226	1,594
Yes	6%	Yes	6%	0	0	170	412	872	1,267	1,594
Yes	6%	Yes	7%	0	170	332	870	1,337	1,659	2,108
Yes	6%	Yes	8%	129	282	870	1,337	1,738	2,227	2,810
Yes	Accel.	Yes	6%	170	892	1,506	2,108	2,799	3,042	3,543
Yes	Accel.	Yes	7%	547	1,295	2,000	2,754	3,064	3,585	4,124
Yes	Accel.	Yes	8%	930	1,770	2,688	3,072	3,756	4,221	4,546

See following page for assumptions.

ASSUMPTIONS FOR TABLE 3.5

(1) Where applicable, debt financing is at 12% and is assumed to be at 80% of costs amortized over a period of 30 years. Note that this type of financing may not be possible because it results in negative before-tax cashflows for up to 10 years as shown in Table 3.3. This is discussed further in the next chapter.

(2) Accelerated capital cost allowance is calculated using the 25%, 50%, 25% formula. (Reference 11)

(3) General inflation of 6%.

(4) Target rate of return of 15%.

(5) Time horizon of 50 years.

(6) Operation and maintenance costs of 1.2% of capital costs.

(7) Water rent of $2.50 per 1000 kW.h per year plus $5.00 per kW of installed capacity.

(8) Income tax rate of 50%.

(9) Losses can be written off against other income.

(10) Two year construction period.

(11) 14% construction financing rate.

(12) Management fee of 8% of capital costs during construction.

Therefore, on a before-tax/no debt basis for a power inflation rate of 7% (1% above the general inflation rate), a power price of 40 to 45 mills would be required for as much power to be financially feasible as was found to be economically feasible (1370 GW.h/year). On an after-tax/no debt basis the price would have to be over 50 mills while on an after-tax/debt basis more than enough power would be feasible at a price of 25 mills (assuming the availability of accelerated capital cost allowance). However, a price of 35 to 40 mills would be required if only the standard 6 percent capital cost allowance were available. If the typical developer did not have other taxable income to use the tax shelter benefits then the pricing of feasible power would be similar to the no tax/debt case. This is because no tax would be payable until the project was fully depreciated which would take many years. In this case a price of about 40 mills would be necessary to make feasible the desired amount of power.

4. POLICY OPPORTUNITIES TO MATCH THE ECONOMIC AND FINANCIAL FEASIBILITY OF THE SMALL HYDRO POWER RESOURCE

Government policy towards a resource should be to encourage development of the economically feasible quantity, timed such as to maximize the net present value of its development consistent with provincial demand. Based on the preceding analysis we have estimated that at least 1370 GW.h/year of energy (the best 54 small hydro power sites), should be seriously considered for connection to the integrated grid(1). The optimal timing might be such that enough power is available to help meet provincial load growth by about the year 1990 based on current demand forecasts.

The financial analysis indicates that under some conditions at least this much power could be financially feasible at present. However, there are impediments which make it unlikely that this much power would be undertaken by private developers in the foreseeable future. Assuming that B C Hydro will not develop this power itself, then the appropriate role for public policy would be to ensure the development of the power by the private sector.

4.1 OBJECTIVES OF POLICY

An effective policy toward small hydro power development should respond to the following problems and objectives:

Ensure Proper Level of Development

The most important objective is to ensure that the small hydro power resource is neither underdeveloped nor overdeveloped. It should ensure an orderly staged development of the better sites as the power is required. The economic section of this study provides a framework for determining the optimal staging and ultimate level of development of the small hydro power resource although more detailed site-specific studies will be required to confirm the result.

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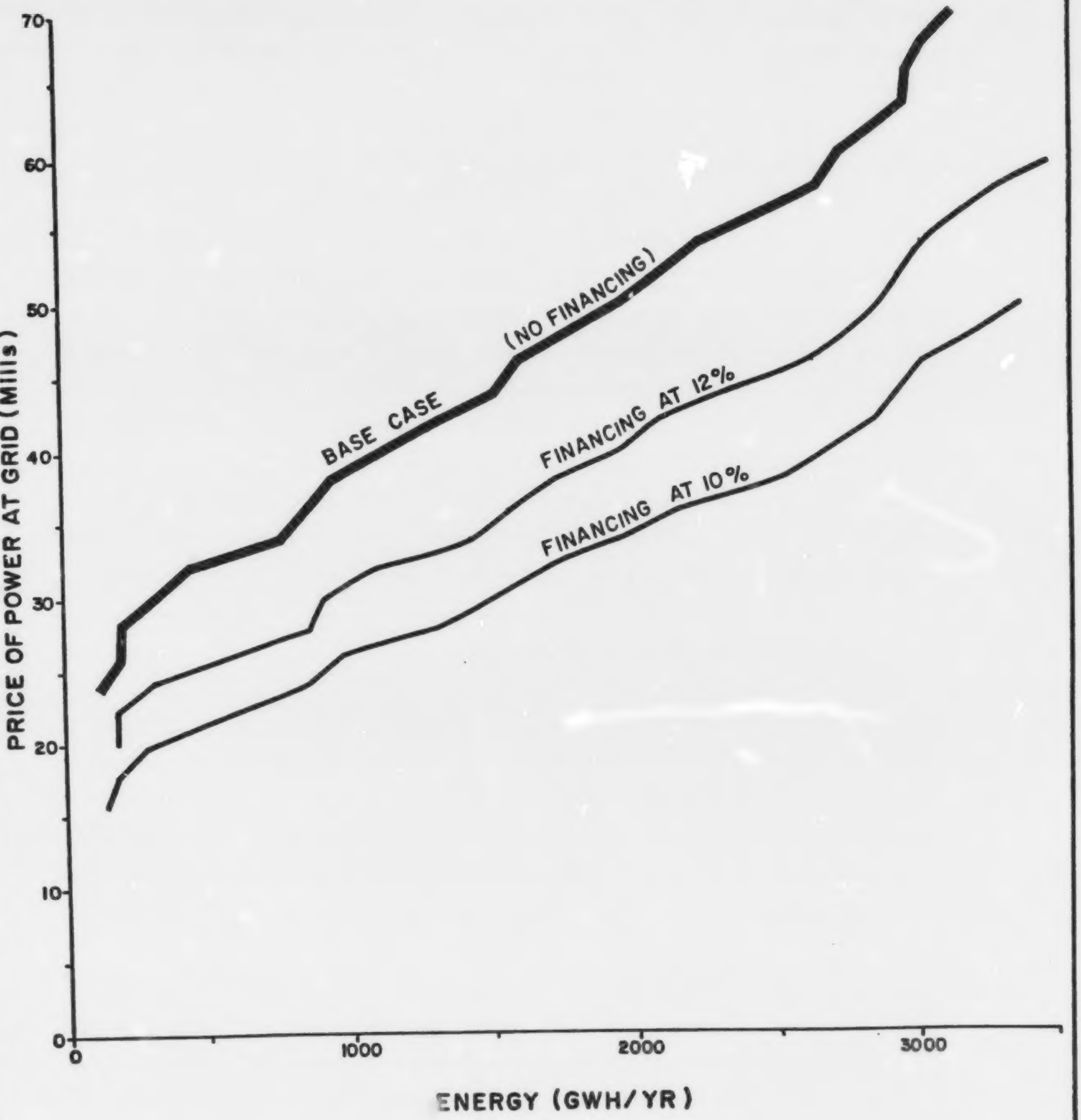
(1) Note that because of the survey nature of this study that has not allowed site-specific analysis, some of these sites may not be developable due to environmental or other constraints. However, it is likely that some good low head or other sites have been missed which would tend to counterbalance these losses.

The optimal level of development should be based on the cost of electric power that could be deferred by the development of the small hydro power resource. All small hydro power sites that can provide power at a lower cost than the next best alternative should be developed, subject to technical, environmental and other constraints. It was estimated that approximately 1370 GW.h per year (54 sites) of energy could be provided for a lower cost than 35 mills which is our estimated economic cost of power from Peace Site C. Peace Site C is the next scheduled large hydro power site to be developed. Development of the small hydro power resource can therefore be timed so that substantial power is available around 1990 when provincial load is forecast to exceed supply.

Project Financing by the Private Developer

We have discussed the difficulty of debt financing of small hydro power developments. The problem is that hydro power projects are capital intensive so that conventional level-payment loans result in many years of negative cashflows. Appropriate financing can have a dramatic effect on project feasibility (see Figure 4.1). However, the commercial financial market is unlikely to entertain with great enthusiasm, loans on projects that might experience up to 10 years of negative pre-tax cash flows. This is true even for developers who are eligible for tax benefits large enough to offset early operating losses. It is considered that to be viable a project should be able to stand alone without the benefit of tax write-offs.

One indicated remedy would be to establish a re-financing scheme which would permit the developer to obtain positive cash flows in the early years in exchange for a reduction in future cash flows. This could be done at normal commercial interest rates and thus would not represent a subsidy. However, such loans are not likely to be available from the conventional financial markets at present. They might be available in the future after there are enough successful projects in operation to demonstrate their feasibility. However this may take years. One alternative is that such loans might be available if they were guaranteed by the government. However, a potential problem with this solution is that the government may be forced to take over many of these projects after the tax benefits to the developer are exhausted.



IMPACT OF FINANCING ON
QUANTITY OF FEASIBLE ON-GRID POWER

FIGURE 4.1

It would appear preferable to develop a policy that does not tamper with the normal financing mechanism for projects. The policy should more directly address the features of small hydro power projects which are causing negative cash flows.

Power Price Structure

The price at which the operator of a small hydro power plant can sell power is obviously a critical factor affecting feasibility. The two main aspects to power pricing are the price level and the assurance of the future price level. The price level should be related to the value of power to the purchaser. B C Hydro has estimated its marginal cost of expanding system capacity to be 35.9 mills at a discount rate of 8 percent (Reference 5). The economic cost of Peace Site C power was estimated to be about 35 mills. These factors indicate that when the demand for power in British Columbia exceeds the present system capacity, the cost of additional power capacity will be at least 35 mills. Thus, in the following analysis, a 35 mill purchase price of power was assumed. In fact a higher purchase price may be warranted when other financial factors related to large hydro power development are considered.

Much more study could be devoted to developing a more accurate value based on avoided cost. Factors that should be considered include the value of non-firm power; the additional value of avoiding some transmission losses by direct supply to the lower voltage segments of the grid; and the possible use of a dual level price scheme whereby the firm portion of the power from a site is paid for at a higher price.

Another option could be to permit the wheeling of power through the B C Hydro grid. This would allow a small hydro power operator to contract to sell power to a user anywhere on the grid at rates and on terms agreeable to both parties and pay a fee to BC Hydro for the use of the grid. For example, it might be possible for developers to supply power to West Kootenay Power and Light from anywhere in British Columbia.

In general, it is considered that the pricing of power should be required to reflect its value and the amount of small hydro power that is feasible at that price should be developed. This is the approach which has been taken in the United States where generation-related payments to private power facilities are required to be based on the marginal energy cost of the purchasing utility. If under these conditions not as much power is financially feasible as would be desirable based on economic considerations, then there must be other distortions in the market that should be corrected by appropriate policies.

Optimal Development Timing

The development of small hydro power sites should be phased to match provincial demand. If development timing decisions were left entirely to the private sector, there would be no assurance of achieving this because of long development lead times, uncertainty of approval and imperfections in the pricing mechanism as a guide to project timing.

One option would be to control development timing with a provincial agency that licenses sites for development as required based on forecasts of demand. This would require a reasonably accurate inventory of the resource so that appropriate planning could be done. Site licences would tend to limit speculation.

Another method of controlling the timing of development would be to issue energy purchase contracts only when needed to meet forecast demand, but to depend on the private sector to find the sites and propose them for development.

Uncertainty of Approval

Another problem at present is the possibility of bureaucratic blockages which have to be overcome before a project can be developed. Three types of provincial legislation are involved - water rights, environmental considerations and electrical distribution. There is no streamlined mechanism for moving a project through these approvals. Coupled with the high cost of initial feasibility studies, this could represent a serious impediment to the development of otherwise feasible sites.

Two policies are proposed here for dealing with these impediments. First, the provincial government could undertake more detailed studies of the resource to help to reduce the front-end study costs of the developer. This would also provide the information necessary to confidently plan the staging of development of the sites. Second, approval procedures should be streamlined. Assuming a policy of controlling the timing of development by licensing, a policy of reasonably assured approval of a site in a standard period of time could be provided when a site is licensed.

Environmental Considerations

Small hydro power development is likely to be less environmentally damaging than large scale hydro power development. However, there are probably financially feasible sites that should not be developed for environmental reasons. The Ontario government has undertaken a blanket study of the environmental impact of small hydro power development which should help to reduce the costs of impact analysis for each site (Reference 10). This may also prove to be a valuable approach in British Columbia.

4.2 POLICIES

Given the above general policies and objectives, this section considers specific options to adjust the amount of feasible small hydro power to achieve the desired level of development.

Overcoming Early Negative Cash Flows

There are three options. The price at which power is bought could be adjusted so that it is always high enough to cover operating costs and debt service. However as discussed above, tampering with the price mechanism is likely to disrupt the objective of achieving efficient development of the resource through the market.

A second option would be for the government to either provide financing directly or to provide loan guarantees for at least enough debt to cover the early deficits. However, it would probably be best to avoid this option if possible, as the prospect of incurring extra debt is unlikely to be appealing to the government. Also, it would be preferable to depend on the efficiency of the financial markets to provide appropriate rates and terms of financing as small hydro power projects become more accepted as a type of investment.

The final option would be to allow relief from provincial taxation at least during the critical early years of a project. This could involve either the water rent, the school tax or both. There are good reasons why relief from these taxes might be considered. It can be argued that the water rent should be reduced or eliminated because 'run of the river' small hydro power plants will not impede the normal flow of water in a stream and are not likely to cause environmental damage.

The school tax might be relaxed because the large hydro power projects which are being compared to small hydro power projects are specifically exempted from paying school tax. Furthermore, if these taxes were not relaxed many otherwise feasible small hydro power projects might not be developed, and thus would not have generated tax revenues anyway.

Table 4.1 (3 sheets) shows a printout of the impact of eliminating these taxes for a typical project. It can be seen that positive pre-tax cash flows are possible from the start of a project. Figure 4.2 illustrates the possible effect on the supply of power by elimination of the water rent.

Table 4.2 shows how reduction or elimination of these taxes could affect the number of years of negative cashflows. It can be seen that given an on-grid price of 35 mills, the elimination of both school tax and water rent could result in the feasibility of about 1245 GW.h/year of energy from small hydro power development. This assumes that a project would not be feasible if it is likely to produce more than four years of negative cashflows.

Table 4.1 Effect on Cash Flows of Eliminating School Tax and Water Rent (Part 1)

```
PEAK POWER OUTPUT (KW)                      4,500
ENERGY OUTPUT (GWH/YR)                       19.5
HARD COST OF PLANT ($1000)                4,536.0
HARD COST OF TRNSMISSION ($1000)            900.0
TOTAL HARD CAPITAL COST ($1000)           5,436.0
FIRMNESS FACTOR (%)                          55.0

START YEAR                                   1982
HORIZON (YRS OF OPERATION)                   50.0
DOWNTIME & XMISSION LOSSES (%)               10.0
DESIRED RATE OF RFTURN (%)                   15.0
POWER INFLATION RATE (%)                      7.0
GFNERAL INFLATION RATE (%)                    6.0
1ST YR. O & M (TRANSMISSION)                  1.2 PERCENT OF CAPITAL COSTS
1ST YR. O & M (GENERATION)                    1.2 PERCENT OF CAPITAL COSTS
AVERAGE ASSET LIFF (YEARS)                  1,000
EQUITY (% OF DEVEL. COST)                    20.0
LOAN AMOUNT (SEE AT RIGHT)                5,147.3
EQUITY AMOUNT (SFE AT RIGHT)              1,286.8
DEBT INTEREST RATF (%)                       12.0
AMORTIZATION PERIOD (YEARS)                  30.0
LOAN PAYMENT ($1000)                        639.0
INCOME TAX RATE (%)                          50.0
ASSESSMENT RATIO (%)                         35.0
UTILITY TAX RATE (% OF POWER)                 0.0
MEAN XMISSION LOSS TO USER (%)                9.0
MEAN SYSTEM MILL RATE                        31.5
SCHOOL TAX RATE (MILLS)                       0.0
WATER RENT:
   ON ENERGY PRODUCED                        0.00  DOLLARS PFR 1000 KW/YEAR
   ON INSTALLED CAPACITY
      DURING CONSTRUCTION                    0.00  DOLLARS PER KWH OF CAPACITY/YEAR
      DURING OPERATION                       0.00  DOLLARS PFR KWH OF CAPACITY/YEAR
CONSTRUCTION INTEREST RATE (%)               14.0
DFVELOPMENT PERIOD (YEARS)                      2
MANAG. FEE (% OF CAPITAL COST)                8.0

CAPITAL COST ALLOWANCE (%)                    6.0 (ENTFR -1 FOR ACCELERATED RATF)
DEBT COVERAGE RATIO                         -1.00 (ENTER -1 FOR NO DEBT PAYMENT CEILING)

UNINTERRUPTABLE POWER:
   SALE PRICE (MILLS)                         0.0
   PERCENT OF TOTAL POWER                     0.0
INTERRUPTIBLE POWER:
   SALE PRICF (MILLS)                        35.0
   PFRCENT OF TOTAL POWFR                   100.0              OPERATIONAL PERIOD
```

Table 4.1 Effect on Cash Flows of Eliminating School Tax and Water Rent (Part 2)

DEVELOPMENT PERIOD

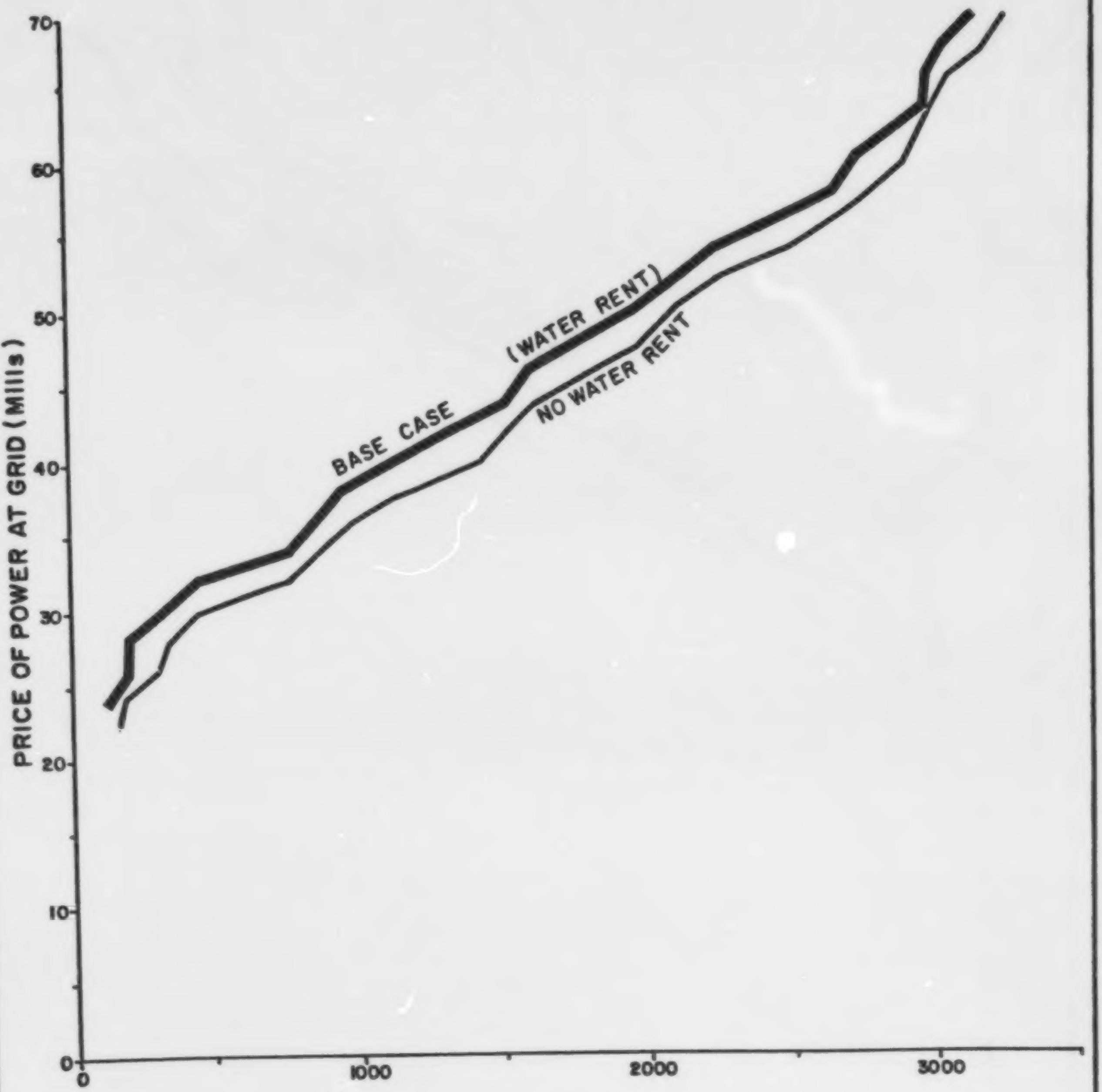
YEAR	CONSTRUCTION COST	MANAGEMENT COST	EQUITY DURING CONSTRUCTION	INTEREST COST	CUMULATIVE DEBT	CUMULATIVE COST	LONG TERM LOAN DRAW	TOTAL EQUITY
1982	1,812.0	145.0	391.4	109.6	1,675.2	2,066.5	0.0	391.4
1983	3,624.0	289.9	782.8	453.7	5,260.0	6,434.2	5,147.3	895.4
1984	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1985	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1986	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1987	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1988	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	5,436.0	434.9	1,174.2	563.3	5,260.0	6,434.2	5,147.3	1,286.8

PRESENT VALUES AND RATES OF RETURN

PRESENT VALUE BEFORE INCOME TAX	2,394.3
PRESENT VALUE AFTER INCOME TAX	1,236.2
IRR AFTER INCOME TAX	23.4

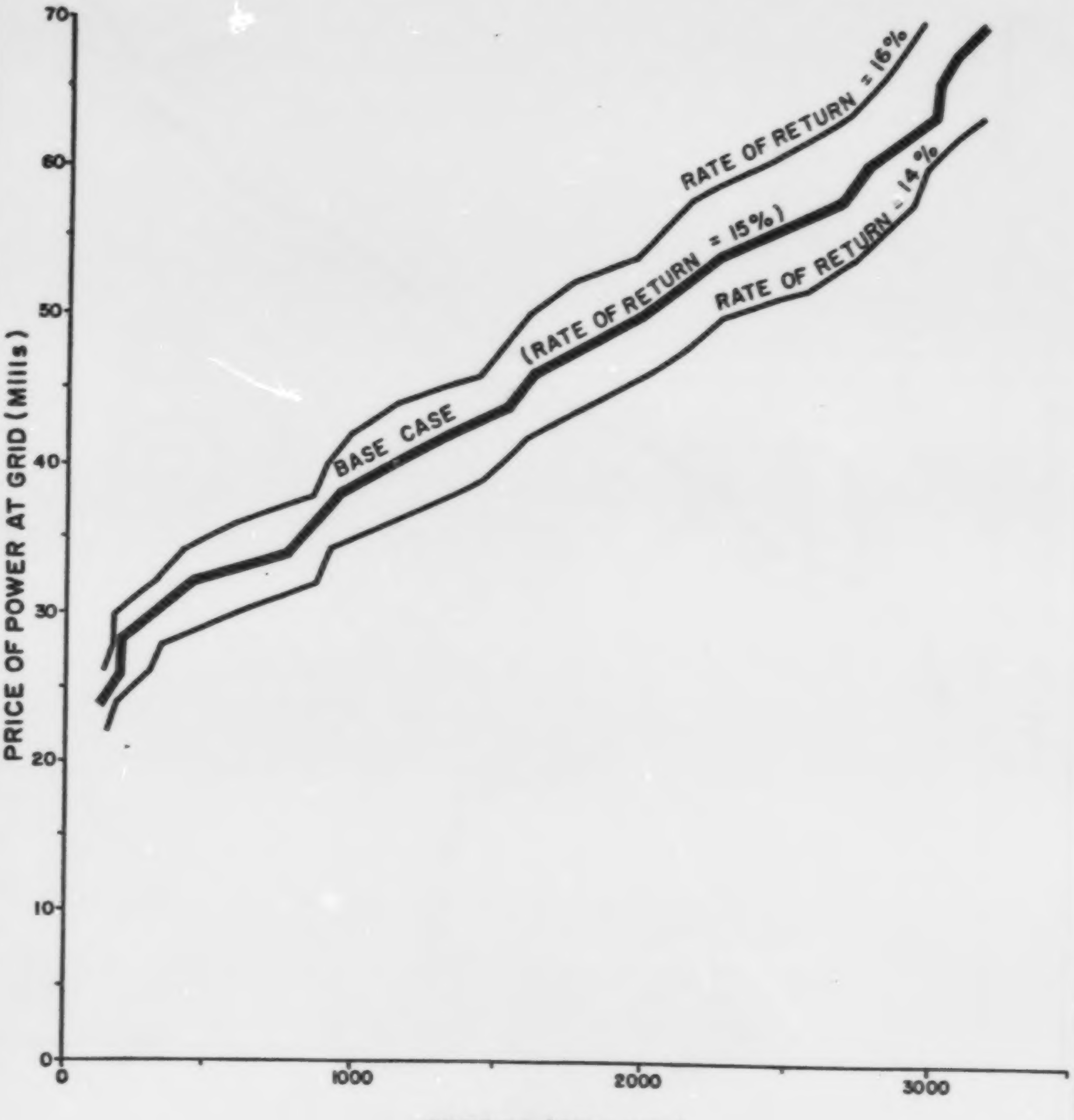
Table 4.1 Effect on Cash Flows of Eliminating School Tax and Water Rent (Part 3)

YEAR	[illegible]			OPERATION AND MAINTENANCE	WATER RENT	SCHOOL TAX	UTILITY TAX	NET INCOME	TOTAL LOAN PAYMENT	PRINCIPAL BALANCE (YR END)	INTEREST PAYMENT	EQUITY INFLOW	BEFORE TAX CASH FLOW	UNDEPREC. BALANCE (YR END)	CAPITAL COST ALLOWANCE	TAXABLE INCOME	TAX PAYMENT	AFTER TAX CASH FLOW
	INTERRUP.	UNINTERRUP.	TOTAL															
1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	371.4	-371.4	0.0	0.0	0.0	0.0	-371.4
1983	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,117.3	0.0	895.4	-895.4	6,434.2	0.0	0.0	0.0	-895.4
1984	781.9	0.0	781.9	73.3	0.0	0.0	0.0	708.6	639.0	5,126.0	617.7	0.0	69.6	6,048.1	386.1	-295.2	-147.6	217.2
1985	836.6	0.0	836.6	77.7	0.0	0.0	0.0	758.9	639.0	5,102.1	615.1	0.0	119.9	5,685.2	362.9	-219.1	-109.5	229.4
1986	895.2	0.0	895.2	82.4	0.0	0.0	0.0	812.8	639.0	5,075.4	612.3	0.0	173.8	5,344.1	341.1	-140.6	-70.3	244.1
1987	957.9	0.0	957.9	87.3	0.0	0.0	0.0	870.6	639.0	5,045.4	609.0	0.0	231.6	5,023.5	320.6	-59.1	-29.5	261.1
1988	1,024.9	0.0	1,024.9	92.5	0.0	0.0	0.0	932.4	639.0	5,011.8	605.4	0.0	293.4	4,722.1	301.4	25.5	12.8	280.6
1989	1,096.7	0.0	1,096.7	98.1	0.0	0.0	0.0	998.6	639.0	4,974.2	601.4	0.0	359.6	4,438.7	283.3	113.8	56.9	302.7
1990	1,173.4	0.0	1,173.4	104.0	0.0	0.0	0.0	1,069.5	639.0	4,932.2	596.9	0.0	430.5	4,172.4	266.3	206.3	103.1	327.3
1991	1,255.6	0.0	1,255.6	110.7	0.0	0.0	0.0	1,145.4	639.0	4,885.0	591.9	0.0	506.4	3,922.1	250.3	303.2	151.6	354.8
1992	1,343.5	0.0	1,343.5	116.9	0.0	0.0	0.0	1,226.6	639.0	4,832.2	586.2	0.0	587.6	3,686.7	235.3	405.1	202.6	385.1
1993	1,437.5	0.0	1,437.5	123.8	0.0	0.0	0.0	1,313.7	639.0	4,773.1	579.9	0.0	674.7	3,465.5	221.2	512.6	256.3	418.4
1994	1,538.1	0.0	1,538.1	131.2	0.0	0.0	0.0	1,406.9	639.0	4,706.8	572.8	0.0	767.9	3,257.6	207.9	626.2	313.1	454.8
1995	1,645.8	0.0	1,645.8	139.1	0.0	0.0	0.0	1,506.7	639.0	4,632.6	564.8	0.0	867.7	3,062.2	195.5	746.4	373.2	494.5
1996	1,761.0	0.0	1,761.0	147.5	0.0	0.0	0.0	1,613.5	639.0	4,549.5	555.9	0.0	974.5	2,878.4	183.7	873.9	436.9	537.6
1997	1,884.3	0.0	1,884.3	156.3	0.0	0.0	0.0	1,728.0	639.0	4,456.4	545.9	0.0	1,089.0	2,705.7	172.7	1,009.3	504.7	584.3
1998	2,016.2	0.0	2,016.2	165.7	0.0	0.0	0.0	1,850.5	639.0	4,352.2	534.8	0.0	1,211.5	2,543.4	162.3	1,153.4	576.7	634.8
1999	2,157.3	0.0	2,157.3	175.7	0.0	0.0	0.0	1,981.7	639.0	4,235.5	522.3	0.0	1,342.7	2,390.8	152.6	1,306.8	653.4	689.3
2000	2,308.3	0.0	2,308.3	186.2	0.0	0.0	0.0	2,122.1	639.0	4,104.7	508.3	0.0	1,483.1	2,247.3	143.4	1,470.4	735.2	747.9
2001	2,469.9	0.0	2,469.9	197.4	0.0	0.0	0.0	2,272.5	639.0	3,958.3	492.6	0.0	1,633.5	2,112.5	134.8	1,645.1	822.6	811.0
2002	2,642.8	0.0	2,642.8	209.2	0.0	0.0	0.0	2,433.6	639.0	3,794.2	475.0	0.0	1,794.6	1,985.7	126.7	1,831.9	915.9	878.7
2003	2,827.8	0.0	2,827.8	221.8	0.0	0.0	0.0	2,606.0	639.0	3,610.5	455.3	0.0	1,967.0	1,866.6	119.1	2,031.6	1,015.8	951.2
2004	3,025.7	0.0	3,025.7	235.1	0.0	0.0	0.0	2,790.7	639.0	3,404.8	433.3	0.0	2,151.7	1,754.6	112.0	2,245.4	1,122.7	1,029.0
2005	3,237.6	0.0	3,237.6	249.2	0.0	0.0	0.0	2,988.4	639.0	3,174.4	408.6	0.0	2,349.4	1,649.3	105.3	2,474.5	1,237.3	1,112.1
2006	3,464.2	0.0	3,464.2	264.1	0.0	0.0	0.0	3,200.1	639.0	2,916.3	380.9	0.0	2,561.1	1,550.4	99.0	2,720.3	1,360.1	1,201.0
2007	3,706.7	0.0	3,706.7	280.0	0.0	0.0	0.0	3,426.7	639.0	2,627.2	350.0	0.0	2,787.7	1,457.3	93.0	2,983.7	1,491.9	1,295.8
2008	3,966.1	0.0	3,966.1	296.7	0.0	0.0	0.0	3,669.4	639.0	2,303.5	315.3	0.0	3,030.4	1,369.9	87.4	3,266.7	1,633.3	1,397.0
2009	4,243.8	0.0	4,243.8	314.6	0.0	0.0	0.0	3,929.2	639.0	1,940.9	276.4	0.0	3,290.2	1,287.7	82.2	3,570.6	1,785.3	1,504.9
2010	4,540.8	0.0	4,540.8	333.4	0.0	0.0	0.0	4,207.4	639.0	1,534.8	232.9	0.0	3,568.4	1,210.4	77.3	3,897.2	1,948.6	1,619.8
2011	4,858.7	0.0	4,858.7	353.5	0.0	0.0	0.0	4,505.2	639.0	1,080.0	184.2	0.0	3,866.2	1,137.8	72.6	4,248.4	2,124.2	1,742.0
2012	5,198.8	0.0	5,198.8	374.7	0.0	0.0	0.0	4,824.1	639.0	570.5	129.6	0.0	4,185.1	1,069.5	68.3	4,626.3	2,313.1	1,872.0
2013	5,562.7	0.0	5,562.7	397.1	0.0	0.0	0.0	5,165.6	639.0	0.0	68.5	0.0	4,526.6	1,005.4	64.2	5,032.9	2,516.5	2,010.1
2014	5,952.1	0.0	5,952.1	421.0	0.0	0.0	0.0	5,531.1	0.0	0.0	0.0	0.0	5,531.1	945.1	60.3	5,470.8	2,735.4	2,795.7
2015	6,369.2	0.0	6,369.2	446.7	0.0	0.0	0.0	5,922.5	0.0	0.0	0.0	0.0	5,922.5	888.4	56.7	5,865.8	2,932.9	2,989.6
2016	6,814.6	0.0	6,814.6	473.0	0.0	0.0	0.0	6,341.6	0.0	0.0	0.0	0.0	6,341.6	835.0	53.3	6,288.3	3,144.1	3,197.4
2017	7,291.6	0.0	7,291.6	501.4	0.0	0.0	0.0	6,790.2	0.0	0.0	0.0	0.0	6,790.2	784.9	50.1	6,740.1	3,370.1	3,420.2
2018	7,802.0	0.0	7,802.0	531.5	0.0	0.0	0.0	7,270.5	0.0	0.0	0.0	0.0	7,270.5	737.8	47.1	7,223.4	3,611.7	3,658.8
2019	8,348.1	0.0	8,348.1	563.3	0.0	0.0	0.0	7,784.8	0.0	0.0	0.0	0.0	7,784.8	693.6	44.3	7,740.5	3,870.3	3,914.5
2020	8,932.5	0.0	8,932.5	597.2	0.0	0.0	0.0	8,335.4	0.0	0.0	0.0	0.0	8,335.4	652.0	41.6	8,293.7	4,146.9	4,188.5
2021	9,557.8	0.0	9,557.8	633.8	0.0	0.0	0.0	8,924.0	0.0	0.0	0.0	0.0	8,924.0	612.8	39.1	8,884.9	4,442.4	4,481.6
2022	10,226.9	0.0	10,226.9	671.0	0.0	0.0	0.0	9,555.9	0.0	0.0	0.0	0.0	9,555.9	576.1	36.8	9,519.1	4,759.5	4,796.3
2023	10,942.7	0.0	10,942.7	711.2	0.0	0.0	0.0	10,231.5	0.0	0.0	0.0	0.0	10,231.5	541.5	34.6	10,196.9	5,098.5	5,133.0
2024	11,708.7	0.0	11,708.7	753.9	0.0	0.0	0.0	10,954.8	0.0	0.0	0.0	0.0	10,954.8	509.0	32.5	10,922.3	5,461.2	5,493.6
2025	12,528.3	0.0	12,528.3	799.1	0.0	0.0	0.0	11,729.2	0.0	0.0	0.0	0.0	11,729.2	478.5	30.5	11,698.7	5,849.3	5,879.9
2026	13,405.3	0.0	13,405.3	847.1	0.0	0.0	0.0	12,558.2	0.0	0.0	0.0	0.0	12,558.2	449.8	28.7	12,529.5	6,264.8	6,293.5
2027	14,343.7	0.0	14,343.7	897.9	0.0	0.0	0.0	13,445.8	0.0	0.0	0.0	0.0	13,445.8	422.8	27.0	13,418.8	6,709.4	6,736.4
2028	15,347.7	0.0	15,347.7	951.8	0.0	0.0	0.0	14,395.9	0.0	0.0	0.0	0.0	14,395.9	397.4	25.4	14,370.6	7,185.3	7,210.7
2029	16,422.1	0.0	16,422.1	1,008.9	0.0	0.0	0.0	15,413.2	0.0	0.0	0.0	0.0	15,413.2	373.6	23.8	15,389.3	7,694.7	7,718.5
2030	17,571.6	0.0	17,571.6	1,069.4	0.0	0.0	0.0	16,502.2	0.0	0.0	0.0	0.0	16,502.2	351.2	22.4	16,479.8	8,239.9	8,262.3
2031	18,801.6	0.0	18,801.6	1,133.6	0.0	0.0	0.0	17,668.0	0.0	0.0	0.0	0.0	17,668.0	330.1	21.1	17,647.0	8,823.5	8,844.6
2032	20,117.7	0.0	20,117.7	1,201.6	0.0	0.0	0.0	18,916.1	0.0	0.0	0.0	0.0	18,916.1	310.3	19.8	18,896.3	9,448.2	9,468.0
2033	21,526.0	0.0	21,526.0	1,273.7	0.0	0.0	0.0	20,252.3	0.0	0.0	0.0	0.0	20,252.3	291.7	18.6	20,233.7	10,116.8	10,135.4
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PRESENT VALUES OF CASH FLOWS	7,189.6	0.0	7,189.6	605.3	0.0	0.0	0.0	6,584.3	3,177.6		2,878.3	1,017.4	2,389.3		1,390.0	2,316.0	1,158.0	1,231.3



IMPACT OF WATER RENT ON
QUANTITY OF FEASIBLE ON-GRID POWER

FIGURE 4.2



IMPACT OF REQUIRED RATE OF RETURN
ON QUANTITY OF FEASIBLE ON-GRID POWER

FIGURE 4.3

TABLE 4.2

FINANCIAL FEASIBILITY OF SMALL HYDRO POWER FOR ALTERNATIVE POLICIES
(Quantity of Energy in GW.h per year)

Water Rent		School Tax Assessment Ratio	First Year of Non-Negative Pre-Tax Cashflow	Price of Power at Grid (Mills)						
Per kW.h	Per kW.h			20	25	30	35	40	45	50
2.50	5.00	35%	2	0	0	149	282	590	919	1,267
2.50	5.00	35%	4	0	0	170	412	892	1,195	1,594
2.50	0	35%	2	0	0	170	315	672	930	1,290
2.50	0	35%	4	0	129	170	539	919	1,337	1,659
0	0	35%	2	0	129	170	412	870	1,124	1,506
0	0	35%	4	0	170	315	854	1,115	1,506	1,960
0	0	20%	2	0	149	282	637	938	1,439	1,684
0	0	20%	4	0	170	446	919	1,429	1,684	2,108
0	0	0%	2	0	170	432	872	1,337	1,659	2,085
0	0	0%	4	129	315	870	1,245	1,659	2,108	2,659

There are many possible variations. For example the tax holiday could be granted, but only during the first 10 years of a project, possibly with provision for increased tax rates in later years to recapture the losses. Relaxation of most of the water rent and school tax might be required but provision should be made for adjusting the level of exemption as required. It is recommended that further study be devoted to exploring the options.

Auctioning of Water Rights

Granting of blanket tax concessions to all small hydro power developments is likely to make the best sites highly profitable if water licences were offered at a flat rate. This could result in a 'gold rush' to stake out likely sites and a flood of water licence applications which could overload approving agencies. Probably it would be better if a mechanism were established to ensure the orderly development of the resource and the capture of as much of its value as possible for the public purse.

It is proposed that water licences be made available as required by some type of public auction. Thus competition could ensure that excessive profits did not accrue to developers, and that an economically efficient price is charged for water rights. It could also allow the early recapture of tax concessions to the maximum extent possible. For example, an exemption from the water tax would result in higher cash flows to the prospective developers of a site. They could therefore pay more for the right to develop it. Competition for the right to develop the site would result in bids that at least partially recapture the present value of the tax concession. Furthermore the bidding process should help to ensure that sites are developed to their full potential since developers proposing to build an optimally sized plant should be able to out-bid others.

Table 4.3 shows the possible impact of these policies on the feasibility of the resource. The auction value of the resource in the column on the right is the residual present value of the prices developers could pay for all feasible sites under those conditions and still earn the overall rate of return indicated.

It is presumed that the initial developers of sites under this scenario will require a relatively high rate of return. This will be necessary to eliminate the early negative cash flows and to provide an incentive for undertaking a new type of venture. Thus bid prices will be relatively low. As these developments become more familiar, more appropriate financing should become available and target rates of return might drop resulting in increased bid prices. Figure 4.3 shows the impact of the rate of return required by the developer on the supply of small hydro power.

Assuming a 19 percent return for the early projects and a 35 mill price it can be seen from Table 4.3 that 930 GW.h per year of power would be feasible if both school tax and water rent were eliminated. This could generate up to $105 million of revenue from auctioning the 29 feasible sites. If the rate of return were dropped to 17 percent the amount of power would be 1337 GW.h per year and the revenue could be $137 million. This is about the amount of power that was indicated as desirable by the economic study. In the event that the accelerated federal tax write-off was extended then more power than is necessary would result, and the revenue from water licence sales would probably be higher.

A disadvantage of the auction approach is that it requires a relatively high level of involvement by the government in selecting sites for development. The resource could also be developed by the more passive approach of soliciting proposals from prospective developers who seek out sites they wish to develop. Appropriate phasing of development could still be achieved by only granting enough water licences to meet forecasted requirements at a given time. The advantage of this approach is that it is relatively simple. A disadvantage is that it does not generate the revenue that could come from an auction, and some other mechanism would be required to ensure the optimal level of development.

TABLE 4.3 - IMPACT OF ELIMINATING WATER RENT AND/OR SCHOOL TAX

Rate of Return for Developer	Water Rent Paid	School Tax Paid	Capital Cost Allowance	Number of Feasible Sites	Amount of Energy (GW.h/Yr)	Total Residual Value of Feasible Sites (Auction Value) ($1,000)
15	Yes	Yes	All 6%	28	919	29,243
17	Yes	Yes		19	652	12,880
19	Yes	Yes		8	358	6,164
15	No	Yes	All 6%	39	1,115	40,782
17	No	Yes		26	870	20,272
19	No	Yes		16	590	9,569
15	No	No	All 6%	70	1,678	184,824
17	No	No		53	1,337	137,201
19	No	No		29	930	105,796
15	Yes	Yes	All Accelerated	142	2,850	151,064
17	Yes	Yes		135	2,754	110,778
19	Yes	Yes		129	2,696	84,590
15	No	Yes	All Accelerated	153	1,678	78,677
17	No	Yes		149	1,337	40,897
19	No	Yes		146	930	21,877
15	No	No	All Accelerated	285	4,239	322,383
17	No	No		274	4,153	241,726
19	No	No		262	4,069	188,092

Assumptions

All as Table 3.5
Assumes average price of power is 35 mills.

5. CONCLUSIONS AND RECOMMENDATIONS

1. The small hydro power resource represents a significant potential source of power. About 1370 GW.h per year of energy from 54 sites could be generated for supply to the integrated grid at a cost lower than Peace Site C. This is about 29 percent of the output that would be available from Peace Site C, and is probably enough to meet about 2 to 3 years of British Columbia load growth. The average economic cost of this power over all sites would be about 27 mills compared to the cost of Peace Site C which is 35 mills.

2. The majority of the economically feasible on-grid small hydro power resource is located in the Southwest Coast or on Vancouver Island (75 percent). About 17 percent is located in the Interior while only about 8 percent is in the North Coast region.

3. Small hydro power is more flexible in meeting demand growth than large scale hydro power because it requires a shorter lead time for development and can be developed in smaller increments. Also less environmental problems and costs may be anticipated.

4. The net economic benefit of deferring the development of a typical large hydro power project (Peace Site C) by first developing all lower cost small hydro power is about $36 million. This is comprised of about $23 million due to a better matching of demand with supply, and $13 million due to the lower average cost of this block of small hydro power.

5. The financial feasibility of private sector development of small hydro power is very sensitive to factors such as the purchase price of power, the assumed rate of inflation of power prices, the rate of return required by the developer, the tax situation of the developer and the availability of appropriate debt financing. In the most likely financial scenario, a power price of almost 40 mills would be required to encourage private sector development of the economically desirable amount of small hydro power.

6. The currently available federal government accelerated capital cost allowance (Class 34) tax concession for alternative energy sources can greatly increase the amount of financially feasible small hydro power. If all developers of small hydro power projects were assumed to fully take advantage of it, the economically desirable amount of power could be available for a price of under 30 mills. It is scheduled to expire in 1985 which is before most on-grid small hydro power should be developed, but the possibility of an extension exists.

7. Developers of small hydro power will likely have difficulty obtaining debt financing through conventional capital markets assuming no special policies are enacted to deal with the problem. The main reason for the difficulty of financing is that small hydro power projects are capital-intensive resulting in relatively high debt payments in the early years and thus negative pre-tax cash flows. As financial institutions become more familiar with small hydro power development, appropriate financing mechanisms may evolve.

8. The price that B C Hydro pays for power should be based on its incremental cost of providing additional energy generating capacity.

9. The Provincial Government should adopt a policy in respect of the small hydro power resource such that the economically feasible sites are developed at the appropriate time to meet future needs for power. Alternatively, small hydro power development at an earlier time may free up additional firm power for export purposes, and will also serve as demonstration projects or prototypes.

10. Additional incentives should be considered for the development of the small hydro power resource, located in power short areas, diesel areas and developing areas, whereby some infrastructure costs may be avoided.

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APPENDIX 1

APPENDIX 1

CHARACTERISTICS AND COSTS OF SITES WITH POWER COSTING LESS THAN 100 MILLS AT THE GRID

Assumptions:

1. Costs are based on the same methodology as described in Appendix 2 and Appendix 4.

2. Sites are sorted in order of cost per kW.h as delivered to the grid.

3. Sites with "N/A" in the distance to grid column are suitable only for off-grid use.

4. The reader is referred to the Resource Assessment (Reference 1)for more details of the sites.

ECONOMIC COST OF POWER FOR ALL SITES COSTING LESS THAN 10.0 CENTS PER KWH.
(Sorted according to cost)

NAME	LATITUDE	LONGITUDE	CAPACITY (kw)	COST/KWH (cents)	TRANSMISSION DISTANCE (km)
BROWN CR	54 02	129 50	4660	1.7	N/A
MAMQUAM CR	49 43	123 04	28700	1.8	6.0
CERVUS CR	49 51	125 47	3900	2.0	1.6
UNNAMED CR	49 45	123 31	4800	2.0	6.0
ASHLU CR	49 55	123 20	20300	2.3	5.0
JOFFRE CR	49 18	122 35	5200	2.3	10.0
HUNLEN CR	52 17	125 45	10500	2.3	N/A
HIGH FALLS	49 56	123 18	7300	2.4	1.0
THORNHILL	49 40	123 36	3970	2.5	0.0
FURRY CR	49 35	123 13	5800	2.5	6.0
ZEBALLOS(L	49 59	126 45	2300	2.5	N/A
TIPELLA CR	49 45	122 10	3200	2.6	0.0
SECHELT CR	49 40	123 33	6600	2.6	0.5
WEDGE CR	50 10	122 54	5500	2.6	2.0
PERKETTS C	49 53	123 52	4500	2.6	15.0
KOKISH R	50 31	126 52	12000	2.7	0.5
KHTADA CR	54 11	129 36	6690	2.7	0.5
TWENTYONE	50 07	122 59	2900	2.7	1.0
TAQUAT CR	49 45	123 25	6700	2.7	11.0
BIRKENHEAD	50 20	122 43	5100	2.8	1.0
ROGERS CR	49 59	122 27	9100	2.8	1.0
GWILLIM CR	49 45	117 28	4200	2.8	1.0
BIRKENHEAD	50 27	122 41	6700	2.8	2.0
CLARY CR	55 28	129 27	6950	2.8	3.0
UNNAMED CR	52 55	118 53	3450	2.8	11.0
YOUNG CR	52 25	125 53	18000	2.8	N/A
CACOOHTIN	52 26	126 19	2590	2.8	N/A
MILL CR	52 24	126 34	4800	2.8	N/A
RUBBLE CR	49 57	123 07	14700	2.9	4.0
SOUTH CRAN	50 46	118 06	3800	2.9	6.0
UNNAMED CR	49 45	123 27	3500	2.9	11.0
UNNAMED CR	50 01	123 21	3500	2.9	15.0
MAYNARD I	50 24	127 14	4190	3.0	18.0
UCONA R	49 44	125 57	2300	3.1	10.0
UNNAMED CR	52 56	118 53	6800	3.1	11.0
MULVEHILL	50 51	118 07	2000	3.2	0.5
ROSEWALL C	49 27	124 48	2100	3.2	1.0
MAWBY CR	49 53	123 18	2700	3.2	2.0
KLEANZA CR	54 36	128 22	6060	3.2	2.0
AIRPLANE C	49 08	121 37	2000	3.2	7.0
MOOSE R	52 55	118 48	6800	3.2	15.0
TASTSQUAN	52 22	126 45	1200	3.2	N/A
McDONALD C	54 07	129 54	2600	3.3	0.5
McGILLIVAR	50 37	122 26	2900	3.3	1.0
URE CR	50 16	122 35	11800	3.3	10.0
BROWNS R &	49 41	125 09	2100	3.3	2.1
MONMOUTH C	49 43	123 11	2040	3.4	3.0
CHIPMUNK C	49 06	121 39	6500	3.4	3.0
UNNAMED CR	50 57	118 24	2500	3.4	6.0
KAIPIT CR	50 15	126 48	4200	3.4	6.0
OWL CR	50 22	122 44	2400	3.4	1.0
LOST VALLE	50 40	122 18	2300	3.4	6.0
NICOAMEN C	50 16	121 24	2200	3.4	10.0
CRUICKSHAN	49 36	125 15	5800	3.4	18.0
CHICKWAT C	49 49	123 43	4800	3.4	27.0
ARDEN CR	54 19	129 41	2900	3.4	N/A

BOX CANYON	49 35	123 24	2100	3.5	2.0
UNNAMED CR	49 47	123 34	4600	3.5	17.0
UNNAMED CR	49 43	123 45	3200	3.5	17.0
HIGH CR	49 55	123 52	3300	3.5	21.0
ELAHO CR	50 07	123 26	19400	3.5	27.0
HANDY CR	49 00	124 56	2700	3.5	29.0
NOOKLIKONN	52 22	126 34	4480	3.5	N/A
TSABLE R	49 31	124 54	2400	3.6	4.0
BEATRICE C	49 50	117 28	4900	3.6	7.0
CAMERON R	49 15	124 40	2200	3.6	9.0
PIGGOTT CR	49 49	125 22	1900	3.6	14.0
UNNAMED CR	49 45	123 43	2340	3.6	18.0
HADOW CR	50 40	117 48	4200	3.6	41.0
LIZZIE CR	50 12	122 28	5700	3.7	1.0
KWINATAHL	55 25	129 08	6000	3.7	1.0
CLAYTON FA	52 22	126 49	2900	3.7	N/A
SNOOTLI CR	52 23	126 36	2420	3.7	N/A
UNNAMED CR	49 44	123 32	1300	3.8	5.0
UNNAMED CR	49 46	123 26	2090	3.8	14.0
BEAR CR	49 28	121 46	4100	3.8	20.0
TSEAPSCAHO	52 26	126 24	2470	3.8	N/A
UNNAMED CR	52 10	126 50	3500	3.8	N/A
SMITELY R	52 07	126 39	6500	3.8	N/A
KUSHANAX C	50 16	117 46	6300	3.9	0.0
FRIES CR	49 45	123 09	2000	3.9	3.0
SIWASH CR	49 34	121 24	4200	3.9	12.0
CLOWHOM R	49 50	123 29	3800	3.9	27.0
FALL CR	50 36	118 53	1700	4.0	1.5
WHITE R	50 18	125 56	6300	4.0	2.0
CARIBOU CR	49 59	117 50	5300	4.0	2.5
KOKISH R	50 27	126 47	4700	4.0	3.0
WEE SANDY	50 00	117 25	2300	4.0	10.0
UNNAMED CR	52 54	118 46	2700	4.0	24.0
McDONALD C	50 34	116 25	3100	4.0	28.0
KELSKIIST	55 21	129 42	4500	4.0	28.0
JANET CR	52 23	125 52	4100	4.0	N/A
SICAMOUS C	50 48	118 58	2300	4.1	0.0
STAWAMUS C	49 42	123 07	5500	4.1	3.0
McKELVIE C	49 56	126 39	1580	4.1	4.0
KWOIEK CR	50 07	121 35	18600	4.1	7.0
GRAY CR	49 32	123 45	2490	4.1	8.0
SHAW CR	49 15	116 43	1900	4.1	17.0
UNNAMED CR	49 46	125 41	3500	4.1	20.0
CLINT CR	50 13	116 54	4200	4.2	1.0
NORDSCHOW	52 18	126 03	3790	4.2	N/A
SPUZZUM CR	49 39	121 26	2600	4.3	2.0
WILSON CR	50 08	117 20	3900	4.3	11.0
UNNAMED CR	54 20	129 46	2000	4.3	16.0
UNNAMED CR	49 49	123 23	2200	4.3	17.0
FOSTHALL C	50 22	117 57	3900	4.3	34.0
COGBURN CR	49 33	121 45	4200	4.3	35.0
THOMAS LAK	49 36	122 25	4100	4.3	50.0
UNNAMED CR	52 01	126 32	6280	4.3	N/A
McNAIR CR	49 31	123 30	2800	4.4	1.0
TANTALUS C	49 51	123 15	4900	4.4	2.0
DAHL CR	54 09	128 43	1580	4.4	10.0
TEXAS CR	50 34	121 49	2700	4.4	18.0
BROWNS R &	49 42	125 08	2300	4.5	2.0
LADYBIRD C	49 25	117 40	1780	4.5	2.5
McLENNON R	52 51	119 21	2500	4.5	6.0

BREMNER CR	49 40	122 01	1400	4.5	7.0
CLOWHOM R	49 49	123 23	3400	4.5	19.0
BOISE CR	49 37	122 41	9300	4.5	50.0
CYPRESS CR	49 20	123 14	1000	4.6	0.0
LOFTUS CR	50 56	118 49	1350	4.6	0.5
UNNAMED CR	49 41	123 16	1770	4.6	2.5
TSUIUS CR	50 37	118 40	5300	4.6	7.0
RED TUSK C	49 47	123 25	3300	4.6	13.0
SQUAMISH R	50 10	123 24	11400	4.6	30.0
MASELPANIK	49 07	121 15	5100	4.6	37.0
FISH HATCH	49 36	122 38	5200	4.6	50.0
NOFICK R	52 05	126 34	12200	4.6	N/A
SANCA CR	49 23	116 43	2000	4.7	1.0
CALLAGHAN	50 04	123 06	7000	4.7	2.0
ANDERSON C	49 11	121 43	1300	4.7	5.0
VICTOR CR	50 57	118 24	1100	4.7	6.0
CAYOOSH CR	50 39	122 01	7000	4.7	7.0
LAKE LOVEL	49 48	123 13	5900	4.7	9.0
GOLD CR	49 21	122 27	1900	4.7	16.0
BIG SILVER	49 42	121 51	9500	4.7	50.0
ZEBALLOS L	50 03	126 46	3500	4.7	N/A
UNNAMED CR	50 55	118 07	1500	4.7	N/A
RAINY R	49 32	123 30	3070	4.8	3.0
GOAT CR	54 43	128 46	1120	4.8	4.0
SALMON R	50 05	126 41	2700	4.8	19.0
NEXT CR	49 18	116 45	3000	4.8	22.0
ROARING CR	49 27	122 13	2000	4.8	25.0
EAST CR #2	50 39	117 01	5000	4.8	40.0
UNNAMED CR	52 10	126 50	8400	4.8	N/A
TSINI-TSIN	52 22	126 06	1790	4.8	N/A
YARD CR	50 54	118 48	3290	4.9	0.0
LASCA CR	49 36	117 09	3200	4.9	1.0
KOOKIPI CR	49 59	121 38	11600	4.9	12.0
WRAY CR	49 20	121 18	1800	4.9	12.0
WADY CR	50 24	127 17	1500	4.9	16.0
GRANT BROO	52 54	118 45	4200	4.9	21.0
MOSHER CR	52 25	125 58	3450	4.9	N/A
NOOMST CR	52 26	126 13	1430	4.9	N/A
UNNAMED CR	50 58	118 36	1100	5.0	7.0
BOWBYES CR	54 09	128 42	1230	5.0	8.0
DAVE HENRY	52 45	119 05	2300	5.0	11.0
CASCADE R	56 03	130 02	1800	5.0	17.0
CRAWFORD C	50 45	117 59	1900	5.0	21.0
THORSEN CR	52 21	126 42	3500	5.0	N/A
NOOMST CR	52 23	126 15	4070	5.0	N/A
TRETHEWAY	49 42	122 05	1600	5.1	0.0
WILLIAMS C	54 24	128 25	3290	5.1	6.0
SOWERBY CR	49 19	121 26	4100	5.1	7.0
CULLITON C	49 53	123 09	6800	5.1	15.0
KAIN CR	50 51	116 35	1700	5.1	16.0
HOTNARKO R	52 23	125 45	8500	5.1	N/A
BARNEY GUL	55 57	129 58	1590	5.1	N/A
BLURTON CR	50 41	119 02	1400	5.2	1.0
UNNAMED CR	49 50	121 31	4300	5.2	9.0
CLEMINA CR	52 34	119 05	2700	5.2	10.0
TOMMY CR	50 50	122 31	2500	5.2	20.0
UNNAMED CR	50 59	116 45	2000	5.2	28.0
ZEBALLOS R	50 03	126 47	2400	5.2	N/A
MARMOT R	55 53	130 00	2460	5.2	N/A
SAUNDERS C	49 48	126 01	2000	5.3	2.0

TRUAX CR	50 53	122 38	1400	5.3	16.0
UNNAMED CR	49 57	121 50	5300	5.3	28.0
ATNARKO R	52 10	125 42	20000	5.3	N/A
WRAGGE CR	50 04	117 28	1990	5.4	2.0
DRUMMIE CR	50 52	118 05	1300	5.4	7.0
UNNAMED CR	49 48	123 24	4280	5.4	15.0
EATON CR	49 15	121 23	1900	5.4	16.0
UNNAMED CR	52 21	126 10	2800	5.4	N/A
MOLYBDDDEN	54 34	128 45	1090	5.5	8.5
CHIMDEMASH	54 40	128 22	3950	5.6	0.0
WHITECAP C	50 43	122 18	1050	5.6	1.0
SHANNON CR	50 05	117 29	1900	5.6	2.0
UNNAMED CR	50 10	126 20	1300	5.6	13.0
McKAY CR	54 13	128 25	5370	5.6	18.0
BULLDOG CR	52 39	118 59	3900	5.6	26.0
SWIFTCURRE	53 01	119 17	2550	5.8	0.5
LEINER R	49 56	126 37	1700	5.8	4.0
POST CR	49 05	121 28	1020	5.8	17.0
UNNAMED CR	54 27	130 04	1180	5.8	30.0
UNNAMED CR	50 29	122 22	1500	5.9	8.0
SEDAN CR	55 05	128 12	2030	5.9	8.0
UNNAMED CR	54 11	129 45	1300	5.9	10.0
UNNAMED CR	54 05	129 56	820	5.9	12.0
BERNARD CR	49 52	116 51	2200	5.9	20.0
GOLD R	49 52	126 06	4400	5.9	4.4
MONTAGUE C	50 20	126 12	2400	5.9	22.0
LAFORGUE C	49 14	121 09	1300	5.9	27.0
PHILLIPS C	49 40	125 34	2800	5.9	27.0
GHITA CR	52 51	118 39	5800	5.9	31.0
COLONEL JO	54 13	130 09	610	5.9	N/A
HILLS CR	50 43	119 04	1200	6.0	3.0
EAST TWIN	53 28	120 23	1720	6.0	22.0
CLOWHOM R	49 51	123 27	3100	6.0	25.0
SMITELY R	52 05	126 36	4100	6.0	N/A
HEADQUARTE	49 42	125 07	540	6.1	1.4
SCUZZZY CR	49 49	121 28	3900	6.1	3.0
SOUTH ENGL	49 15	124 17	3300	6.1	5.0
WILSON CR	49 35	116 52	2500	6.1	12.0
HORSFY CR	53 08	119 41	5150	6.1	14.0
UNNAMED CR	54 23	128 53	1800	6.1	15.0
UNNAMED CR	49 55	123 48	3650	6.1	25.0
VANCOUVER	49 56	123 48	3500	6.1	25.0
UNNAMED CR	49 40	123 35	1140	6.2	0.0
MARA CR	50 46	119 00	850	6.2	1.0
CASCADE CR	50 25	117 07	2500	6.2	4.5
STE CROIX	54 42	128 19	1490	6.2	6.0
HARDSCRABB	54 42	128 20	1270	6.2	8.0
CAYOOSH CR	50 39	121 59	4620	6.3	1.0
NEMO CR	49 55	117 25	7100	6.3	3.0
LATEWHOS C	50 27	118 43	2100	6.3	8.0
TZOONIE CR	49 47	123 43	2400	6.3	23.0
WARREN CR	50 58	116 42	5500	6.3	24.0
POOL CR	50 47	117 38	6200	6.3	31.0
CADWALLADE	50 46	122 48	1700	6.4	0.5
LEGERWOOD	50 58	118 46	950	6.4	1.5
CHUA CHUA	51 21	120 07	1500	6.4	2.0
SEASKINNIS	55 16	128 59	2330	6.4	2.0
UNNAMED CR	50 07	126 36	1400	6.4	9.0
DORE R #1	53 16	120 17	4450	6.4	13.0
WALT LAKE	49 53	124 08	750	6.4	16.0

CRAFT CR	50 24	127 15	1500	6.4	18.0
THELWOOD C	49 33	125 34	2100	6.4	41.0
TWIN ONE C	50 15	122 30	6900	6.5	1.0
TLOOLS CR	49 52	125 45	1070	6.5	1.0
UNNAMED CR	49 29	121 25	1300	6.5	3.0
CHASE CR	50 49	119 41	700	6.6	0.0
COOKE CR	50 37	118 50	2700	6.6	0.5
LOST LEDGE	50 06	116 56	860	6.6	0.5
DAVIS CR	50 08	116 57	680	6.6	0.5
NABEELAH C	54 08	128 32	920	6.6	6.0
NEWCASTLE	50 22	126 07	1300	6.6	15.0
YELLOWJACK	52 43	119 03	1400	6.6	17.0
GIEGERICH	50 43	117 07	3300	6.6	55.0
SCHROEDER	50 02	116 55	1400	6.7	0.5
UNNAMED CR	50 30	126 54	620	6.7	1.6
CLUTE CR	50 01	116 53	3500	6.7	8.0
UNNAMED CR	49 41	123 35	1100	6.7	8.0
TAM O'SHAN	49 48	116 51	3400	6.7	3.0
McNULTY CR	49 25	120 05	2200	6.7	10.0
TEMPLETON	50 48	116 29	1800	6.7	21.0
DERRY CR	50 46	118 33	2800	6.7	22.0
HALFWAY HO	50 29	117 51	5700	6.7	22.0
CULTUS CR	49 20	116 47	3400	6.7	25.0
UNNAMED CR	49 09	121 15	1570	6.7	30.0
EAST CR #1	50 39	117 02	2500	6.7	38.0
BEATTON CR	50 44	117 44	3000	6.7	46.0
UNNAMED CR	49 40	121 51	2500	6.7	55.0
KELLIE CR	50 55	117 34	3100	6.7	65.0
NOEL CR	50 46	122 48	1160	6.8	2.0
ROBSON R	53 03	119 13	2690	6.8	2.5
KOKISH R	50 28	126 48	2390	6.8	2.8
WILFRED CR	49 28	124 51	540	6.8	3.5
WHITE CR	54 24	128 41	1390	6.8	8.0
LOKI CR	49 50	116 51	2600	6.8	14.0
POWDER CR	49 53	116 51	3600	6.8	23.0
UNNAMED CR	49 09	121 20	2000	6.8	30.0
UNNAMED CR	50 29	127 21	770	6.9	10.0
EDDY CR	53 14	120 07	1070	6.9	10.0
CAMPBELL C	49 57	116 51	4800	6.9	12.0
SHANNON CR	54 40	127 30	1300	6.9	17.0
NORA CR	50 08	126 02	1200	6.9	22.0
MOAKWA CR	50 07	126 02	2000	6.9	22.0
UNNAMED CR	53 08	120 01	2240	6.9	23.0
BURMAN R	49 36	125 50	1600	6.9	26.0
SACHS CR	53 12	131 58	780	6.9	N/A
ALICE CR	54 40	128 47	1250	7.0	1.8
CHEEKYE R	49 48	123 06	1400	7.0	7.0
MUCHALAT R	49 53	126 19	880	7.0	12.0
COMOX CR	49 32	125 15	720	7.0	18.0
RAPID CR	50 27	117 10	2500	7.0	21.0
TLATLOS CR	50 23	126 14	2700	7.0	26.0
LYNN CR	49 21	123 01	2100	7.1	0.0
CONNEL CR	50 39	122 25	4400	7.1	0.5
MARUILLA C	50 05	126 25	2200	7.1	0.8
UNNAMED CR	50 10	126 18	940	7.1	14.0
CATHERINE	50 25	126 36	1970	7.1	19.0
UNNAMED CR	49 12	121 20	1300	7.1	24.0
AMERICAN C	56 08	129 54	3340	7.1	25.0
MESS CR	57 53	131 12	10300	7.1	N/A
CAMP CR	52 39	119 11	1700	7.2	2.0

ENGLISHMAN	49 15	124 21	3700	7.2	2.3
MACKTUSH C	49 06	124 51	1000	7.2	10.0
BOYD CR	50 53	117 34	4000	7.2	64.0
NOOSGULCH	52 26	126 23	1800	7.2	N/A
HUMMING BI	50 46	119 00	550	7.3	1.0
BUTTERWORT	49 48	125 53	950	7.3	6.3
SMALL CR	53 04	119 35	4000	7.3	7.0
DORE R #2	53 13	120 17	3420	7.3	17.0
UNNAMED CR	49 15	121 15	1200	7.3	25.0
GLACIER CR	55 59	129 56	1270	7.3	N/A
REINECKER	50 47	119 13	690	7.4	4.0
ANDERSON C	54 02	128 43	1140	7.4	5.0
BEECH CR	49 36	125 12	460	7.4	8.2
MAIMEN CR	49 17	121 24	1700	7.4	11.0
UNNAMED CR	50 21	116 51	1000	7.4	15.0
UNNAMED CR	53 10	120 02	1830	7.4	18.0
BOBB CR	50 51	122 33	1700	7.4	22.0
TSILEUH CR	49 46	121 26	4300	7.5	5.0
AYTON CR	54 11	129 43	1000	7.5	6.0
PACKSADDLE	52 48	119 08	1400	7.5	7.5
UNNAMED CR	50 21	126 07	1000	7.5	19.0
UNNAMED CR	49 59	116 03	1600	7.5	25.0
PALMERSTON	50 27	126 16	1100	7.5	28.0
UNNAMED CR	49 29	126 14	980	7.5	32.0
UNNAMED CR	50 10	126 37	1300	7.6	7.0
UNNAMED CR	50 06	116 46	730	7.6	8.0
BOLTON CR	54 13	128 26	2100	7.6	18.0
TROUT CR	54 51	127 19	570	7.7	0.0
KOKISH R	50 29	126 50	3700	7.7	0.7
UNNAMED CR	50 07	116 44	770	7.7	13.0
SHAMES R	54 25	128 54	1880	7.7	15.0
HOPE CR	50 28	117 11	1300	7.7	24.0
PRETTY GIR	49 30	126 14	980	7.7	30.0
ADRIAN CR	49 48	125 27	650	7.8	0.0
UNNAMED CR	54 10	129 56	490	7.8	0.5
BONANZA R	50 20	126 44	1900	7.8	0.8
CLUXEWE R	50 29	127 09	800	7.8	11.0
TEXAS CR	50 31	121 50	1600	7.8	23.0
BANCROFT C	49 34	125 52	1500	7.8	26.0
SEPTET CR	50 48	116 41	1500	7.8	34.0
GRIZZLY CR	51 19	117 25	6500	7.8	50.0
SWAH CR	50 01	126 20	620	7.9	1.9
DENNIS CR	50 02	117 22	930	7.9	2.0
WOODBURY C	49 48	116 57	4190	7.9	6.0
MEMEKAY R	50 10	125 47	1400	7.9	7.5
FOLEY CR	49 08	121 33	1500	7.9	14.0
SALLOOMT C	52 27	126 32	1910	7.9	N/A
CORN CR	49 04	116 40	990	8.0	4.0
JOHN CR	50 16	117 01	800	8.0	4.5
SMYTH CR	50 32	118 43	1200	8.0	15.0
ATLUCK CR	50 18	126 56	1900	8.0	16.0
KINMAN CR	50 21	126 55	980	8.0	21.0
TENDERFOOT	50 28	117 13	2600	8.0	28.0
TLUPANA R	49 46	126 20	1900	8.1	2.0
ASHER CR	50 36	117 29	3600	8.1	54.0
MILL CR	55 06	128 07	1490	8.2	3.0
MEADOW CR	50 18	117 03	800	8.2	4.0
SWIFT CR #	52 52	119 13	2100	8.2	5.0
UNNAMED CR	54 05	128 20	1700	8.2	22.0
DRINKWATER	49 26	125 30	1100	8.2	23.0

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MOWHOKAM C    50 02    121 31    1030    8.3    3.0
UNNAMED CR    50 08    126 37     960    8.3   11.0
UNNAMED CR    54 06    129 55    1250    8.3   12.0
HELLROARER    49 35    118 45    2000    8.3   25.0
BRENNER CR    50 13    117 30    3000    8.3   26.0
BEHRMAN CR    50 30    116 52    1230    8.3   30.0
McDOUGAL C    50 58    117 37    3600    8.3   80.0
WILSON CR     55 03    128 17     950    8.4    5.0
SWANEE CR     49 15    121 23     770    8.4   17.0
KSHADIN CR    55 27    129 03    1980    8.5    6.0
CANTELON /    49 13    121 23    2200    8.5   22.0
FLEET R       48 35    124 03    1800    8.5   24.0
BEDWELL R     49 27    125 36    1100    8.5   32.0
TOWN CR       50 46    117 45    1450    8.5   44.0
LIGNITE CR    53 55    132 37    2060    8.5    N/A
CAUSQUA CR    55 02    127 16     680    8.6    4.5
LEXINGTON     50 50    117 37    1780    8.6   58.0
PERRY R       49 54    126 37    1140    8.7    3.0
COLDWATER     54 20    128 40    1840    8.7    7.5
SONGHEES C    50 47    127 35     990    8.7    8.0
ERLANDSEN     54 36    128 44    1750    8.7    9.0
MARGARET C    49 26    125 27    1000    8.8   23.0
SHEPHERD C    49 38    125 31    1200    8.8   39.0
TAHSISH R     50 13    127 03    1300    8.8   45.0
CHRISTENSO    52 28    126 41    1830    8.8    N/A
KAUWINCH R    50 14    127 16    1000    8.9   24.0
UPANA CR      49 48    126 05    1300    9.0    0.1
DASQUE CR     54 23    128 55    1600    9.0   16.0
ALLAN CR      52 32    119 07    2300    9.1   12.0
ADOLPH CR     52 31    119 23    4300    9.1   29.0
UNNAMED CR    50 29    126 24    1380    9.1   33.0
STIKELAN C    51 27    124 22    2100    9.1    N/A
BIG TREE C    50 15    125 45    1250    9.3    1.5
UNNAMED CR    55 03    128 07    1140    9.3    3.3
LAIDLAW CR    50 52    117 14    2370    9.3   73.0
MACKIN CR     52 22    122 23     860    9.4    2.0
UNNAMED CR    54 19    128 24     790    9.4   10.0
PTARMIGAN     52 35    118 50    4100    9.4   40.0
UNNAMED CR    50 05    126 28     980    9.5    1.2
KEARY CR      50 49    122 25    1700    9.5   12.0
TRENT R       49 35    124 59     700    9.6    4.0
MARION CR     54 22    130 03     870    9.6   20.0
UNNAMED CR    49 57    126 51     380    9.6    N/A
NOR/MID ME    50 11    125 47    1400    9.7    5.5
FITZSTUBBS    50 09    117 22    4900    9.7   13.0
UNNAMED CR    50 20    116 51     620    9.7   14.0
UNNAMED CR    54 22    128 54    1900    9.7   15.0
DAVE HENRY    52 46    119 04    1400    9.7   15.0
DUCK CR       54 20    126 37    1300    9.8    2.3
TALA HAAT     54 46    130 04     660    9.8    5.0
HUMPHRYS C    54 11    128 30    1230    9.8   13.0
ZENITH CR     49 52    123 16     980    9.8   15.0
POPLAR CR     50 26    117 08    3600    9.8   17.0
BRODRICK C    49 50    126 53    1100    9.8   24.0
PAYNE CR      50 37    117 51    1100    9.8   45.0
NAKA CR       50 28    126 25    1400    9.9   31.0

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ECONOMIC COST OF POWER FOR ALL SITES COSTING LESSTHAN 10.0 CENTS PER KWH.
(Sorted Alphabetically)

ALL SITES BELOW 100 MILLS

NAME	LATITUDE	LONGITUDE	CAPACITY (kw)	COST/KWH (cents)	TRANSMISSION DISTANCE (km)
ADOLPH CR	52 31	119 23	4300	9.1	29.0
ADRIAN CR	49 48	125 27	650	7.8	0.0
AIRPLANE C	49 08	121 37	2000	3.2	7.0
ALICE CR	54 40	128 47	1250	7.0	1.8
ALLAN CR	52 32	119 07	2800	9.1	12.0
AMERICAN C	56 08	129 54	3340	7.1	25.0
ANDERSON C	49 11	121 43	1300	4.7	5.0
ANDERSON C	54 02	128 43	1140	7.4	5.0
ARDEN CR	54 19	129 41	2900	3.4	N/A
ASHER CR	50 36	117 29	3600	8.1	54.0
ASHLU CR	49 55	123 20	20500	2.3	5.0
ATLUCK CR	50 18	126 56	1900	8.0	16.0
ATNARKO R	52 10	125 42	20000	5.3	N/A
AYTON CR	54 11	129 43	1000	7.5	6.0
BANCROFT C	49 34	125 52	1500	7.8	26.0
BARNEY GUL	55 57	129 58	1590	5.1	N/A
BEAR CR	49 28	121 46	4100	3.8	20.0
BEATRICE C	49 50	117 28	4900	3.6	7.0
BEATTON CR	50 44	117 44	3000	6.7	46.0
BEDWELL R	49 27	125 36	1100	8.5	32.0
BEECH CR	49 36	125 12	460	7.4	8.2
BEHRMAN CR	50 30	116 52	1230	8.3	30.0
BERNARD CR	49 52	116 51	2200	5.9	20.0
BIG SILVER	49 42	121 51	9500	4.7	58.0
BIG TREE C	50 15	125 45	1250	9.3	1.5
BIRKENHEAD	50 27	122 41	6700	2.8	2.0
BIRKENHEAD	50 20	122 43	5100	2.8	1.0
BLURTON CR	50 41	119 02	1400	5.2	1.0
BOBB CR	50 51	122 33	1700	7.4	22.0
BOISE CR	49 37	122 41	9300	4.5	50.0
BOLTON CR	54 13	128 26	2100	7.6	18.0
BONANZA R	50 20	126 44	1900	7.8	0.8
BOWBYES CR	54 09	128 42	1230	5.0	8.0
BOX CANYON	49 35	123 24	2100	3.5	2.0
BOYD CR	50 53	117 34	4000	7.2	64.0
BREMNER CR	49 40	122 01	1400	4.5	7.0
BRENNER CR	50 13	117 30	3000	8.3	26.0
BRODRICK C	49 50	126 53	1100	9.8	24.0
BROWN CR	54 02	129 50	4660	1.7	N/A
BROWNS R #	49 42	125 08	2300	4.5	2.0
BROWNS R #	49 41	125 09	2100	3.3	2.1
BUCK CR	54 20	126 37	1300	9.8	2.3
BULLDOG CR	52 39	118 59	3900	5.6	26.0
BURMAN R	49 36	125 50	1600	6.9	26.0
BUTTERWORT	49 48	125 53	950	7.3	6.3
CACOOHTIN	52 26	126 19	2590	2.8	N/A
CADWALLADE	50 46	122 48	1700	6.4	0.5
CALLAGHAN	50 04	123 06	7000	4.7	2.0
CAMERON R	49 15	124 40	2200	3.6	9.0
CAMP CR	52 39	119 11	1700	7.2	2.0
CAMPBELL C	49 57	116 51	4800	6.9	12.0
CANTELON /	49 13	121 23	2200	8.5	22.0
CARIBOU CR	49 59	117 50	5300	4.0	2.5
CASCADE CR	50 25	117 07	2500	6.2	4.5
CASCADE R	56 03	130 02	1800	5.0	17.0

CATHERINE	50 25	126 36	1970	7.1	19.0
CAUSQUA CR	55 02	127 16	680	8.6	4.5
CAYOOSH CR	50 39	121 59	4620	6.3	1.0
CAYOOSH CR	50 39	122 01	7000	4.7	7.0
CERVUS CR	49 51	125 47	3900	2.0	1.6
CHASE CR	50 49	119 41	700	6.6	0.0
CHEEKYE R	49 48	123 06	1400	7.0	7.0
CHICKWAT C	49 49	123 43	4800	3.4	27.0
CHIMDEMASH	54 40	128 22	3950	5.6	0.0
CHIPMUNK C	49 06	121 39	6500	3.4	3.0
CHRISTENSO	52 28	126 41	1830	8.8	N/A
CHUA CHUA	51 21	120 07	1500	6.4	2.0
CLARY CR	55 28	129 27	6950	2.8	3.0
CLAYTON FA	52 22	126 49	2900	3.7	N/A
CLEMINA CR	52 34	119 05	2700	5.2	10.0
CLINT CR	50 13	116 54	4200	4.2	1.0
CLOWHOM R	49 49	123 23	3400	4.5	19.0
CLOWHOM R	49 50	123 29	3800	3.9	27.0
CLOWHOM R	49 51	123 27	3100	6.0	25.0
CLUTE CR	50 01	116 53	3500	6.7	8.0
CLUXEWE R	50 29	127 09	800	7.8	11.0
COGBURN CR	49 33	121 45	4200	4.3	35.0
COLDWATER	54 20	128 40	1840	8.7	7.5
COLONEL JO	54 13	130 09	610	5.9	N/A
COMOX CR	49 32	125 15	720	7.0	18.0
CONNEL CR	50 39	122 25	4400	7.1	0.5
COOKE CR	50 37	118 50	2700	6.6	0.5
CORN CR	49 04	116 40	990	8.0	4.0
CRAFT CR	50 24	127 15	1500	6.4	18.0
CRAWFORD C	50 45	117 59	1900	5.0	21.0
CRUICKSHAN	49 36	125 15	5800	3.4	18.0
CULLITON C	49 53	123 09	6800	5.1	15.0
CULTUS CR	49 20	116 47	3400	6.7	25.0
CYPRESS CR	49 20	123 14	1000	4.6	0.0
DAHL CR	54 09	128 43	1580	4.4	10.0
DASQUE CR	54 23	128 55	1600	9.0	16.0
DAVE HENRY	52 45	119 05	2300	5.0	11.0
DAVE HENRY	52 46	119 04	1400	9.7	15.0
DAVIS CR	50 08	116 57	680	6.6	0.5
DENNIS CR	50 02	117 22	930	7.9	2.0
DERRY CR	50 46	118 33	2800	6.7	22.0
DORE R #1	53 16	120 17	4450	6.4	13.0
DORE R #2	53 13	120 17	3420	7.3	17.0
DRINKWATER	49 26	125 30	1100	8.2	23.0
DRUMMIE CR	50 52	118 05	1300	5.4	7.0
EAST CR #2	50 39	117 01	5000	4.8	40.0
EAST CR #1	50 39	117 02	2500	6.7	38.0
EAST TWIN	53 28	120 23	1720	6.0	22.0
EATON CR	49 15	121 23	1900	5.4	16.0
EDDY CR	53 14	120 07	1070	6.9	10.0
ELAHO CR	50 07	123 26	19400	3.5	27.0
ENGLISHMAN	49 15	124 21	3700	7.2	2.3
ERLANDSEN	54 36	128 44	1750	8.7	9.0
FALL CR	50 36	118 53	1700	4.0	1.5
FISH HATCH	49 36	122 38	5200	4.6	50.0
FITZSTUBBS	50 09	117 22	4900	9.7	13.0
FLEET R	48 35	124 03	1800	8.5	24.0
FOLEY CR	49 08	121 33	1500	7.9	14.0
FOSTHALL C	50 22	117 57	3900	4.3	34.0
FRIES CR	49 45	123 09	2000	3.9	3.0

FURRY CR	49 35	123 13	5800	2.5	6.0
GHITA CR	52 51	118 39	5800	5.9	31.0
GIFGERICH	50 43	117 07	3300	6.6	55.0
GLACIER CR	55 59	129 56	1270	7.3	N/A
GOAT CR	54 43	128 46	1120	4.8	4.0
GOLD CR	49 21	122 27	1900	4.7	16.0
GOLD R	49 52	126 06	4400	5.9	4.4
GRANT BROO	52 54	118 45	4200	4.9	21.0
GRAY CR	49 32	123 45	2490	4.1	8.0
GRIZZLY CR	51 19	117 25	6500	7.8	50.0
GWILLIM CR	49 45	117 28	4200	2.8	1.0
HADOW CR	50 40	117 48	4200	3.6	41.0
HALFWAY HO	50 29	117 51	5700	6.7	22.0
HANDY CR	49 00	124 56	2700	3.5	29.0
HARDSCRABB	54 42	128 20	1270	6.2	8.0
HEADQUARTE	49 42	125 07	540	6.1	1.4
HELLROARER	49 35	118 45	2000	8.3	25.0
HIGH CR	49 55	123 52	3300	3.5	21.0
HIGH FALLS	49 56	123 18	7500	2.4	1.0
HILLS CR	50 43	119 04	1200	6.0	3.0
HOPE CR	50 28	117 11	1300	7.7	24.0
HORSEY CR	53 08	119 41	5150	6.1	14.0
HOTNARKO R	52 23	125 45	8500	5.1	N/A
HUMMING BI	50 46	119 00	550	7.3	1.0
HUMPHRYS C	54 11	128 30	1230	9.8	13.0
HUNLEN CR	52 17	125 45	10500	2.3	N/A
JANET CR	52 23	125 52	4100	4.0	N/A
JOFFRE CR	49 18	122 35	5200	2.3	10.0
JOHN CR	50 16	117 01	800	8.0	4.5
KAIN CR	50 51	116 35	1700	5.1	16.0
KAIPIT CR	50 15	126 48	4200	3.4	6.0
KAUWINCH R	50 14	127 16	1000	8.9	24.0
KEARY CR	50 49	122 25	1700	9.5	12.0
KELLIE CR	50 55	117 34	3100	6.7	65.0
KELSKIIST	55 21	129 42	4500	4.0	28.0
KHTADA CR	54 11	129 36	6690	2.7	0.5
KINMAN CR	50 21	126 55	980	8.0	21.0
KLEANZA CR	54 36	128 22	6060	3.2	2.0
KOKISH R	50 27	126 47	4700	4.0	3.0
KOKISH R	50 31	126 52	12000	2.7	0.5
KOKISH R	50 28	126 48	2390	6.8	2.8
KOKISH R	50 29	126 50	3700	7.7	0.7
KOOKIPI CR	49 59	121 38	11600	4.9	12.0
KSHADIN CR	55 27	129 03	1980	8.5	6.0
KUSHANAX C	50 16	117 46	6300	3.9	0.0
KWINATAHL	55 25	129 08	6000	3.7	1.0
KWOIEK CR	50 07	121 35	18600	4.1	7.0
LADYBIRD C	49 25	117 40	1780	4.5	2.5
LAFORGUE C	49 14	121 09	1300	5.9	27.0
LAIDLAW CR	50 52	117 14	2370	9.3	73.0
LAKE LOVEL	49 48	123 13	5900	4.7	9.0
LASCA CR	49 36	117 09	3200	4.9	1.0
LATEWHOS C	50 27	118 43	2100	6.3	8.0
LEGERWOOD	50 58	118 46	950	6.4	1.5
LEINER R	49 56	126 37	1700	5.8	4.0
LEXINGTON	50 50	117 37	1780	8.6	58.0
LIGNITE CR	53 55	132 37	2060	8.5	N/A
LIZZIE CR	50 12	122 28	5700	3.7	1.0
LOFTUS CR	50 56	118 49	1350	4.6	0.5
LOKI CR	49 50	116 51	2600	6.8	14.0

LOST LEDGE	50 06	116 56	860	6.6	0.5
LOST VALLE	50 40	122 18	2300	3.4	6.0
LYNN CR	49 21	123 01	2100	7.1	0.0
MACKIN CR	52 22	122 23	860	9.4	2.0
MACKTUSH C	49 06	124 51	1000	7.2	10.0
MAIMEN CR	49 17	121 24	1700	7.4	11.0
MAMQUAM CR	49 43	123 04	28700	1.8	6.0
MAQUILLA C	50 05	126 25	2200	7.1	0.8
MARA CR	50 46	119 00	850	6.2	1.0
MARGARET C	49 26	125 27	1000	8.8	23.0
MARION CR	54 22	130 03	870	9.6	20.0
MARMOT R	55 53	130 00	2460	5.2	N/A
MASELPANIK	49 07	121 15	5100	4.6	37.0
MAWRY CR	49 53	123 18	2700	3.2	2.0
MAYNARD L	50 24	127 14	4190	3.0	18.0
MEADOW CR	50 18	117 03	800	8.2	4.0
MEMEKAY R	50 10	125 47	1400	7.9	7.5
MESS CR	57 53	131 12	10300	7.1	N/A
MILL CR	52 24	126 34	4800	2.8	N/A
MILL CR	55 06	128 07	1490	8.2	3.0
MOAKWA CR	50 07	126 02	2000	6.9	22.0
MOLYBDDDEN	54 34	128 45	1090	5.5	8.5
MONMOUTH C	49 43	123 11	2040	3.4	3.0
MONTAGUE C	50 20	126 12	2400	5.9	22.0
MOOSE R	52 55	118 48	6800	3.2	15.0
MOSHER CR	52 25	125 58	3450	4.9	N/A
MOWHOKAM C	50 02	121 31	1000	8.3	3.0
MUCHALAT R	49 53	126 19	880	7.0	12.0
MULVEHILL	50 51	118 07	2000	3.2	0.5
McDONALD C	50 34	116 25	3100	4.0	28.0
McDONALD C	54 07	129 54	2600	3.3	0.5
McDOUGAL C	50 58	117 37	3600	8.3	80.0
McGILLIVAR	50 37	122 26	2900	3.3	1.0
McKAY CR	54 13	128 25	5370	5.6	18.0
McKELVIE C	49 56	126 39	1580	4.1	4.0
McLENNON R	52 51	119 21	2500	4.5	6.0
McNAIR CR	49 31	123 30	2800	4.4	1.0
McNULTY CR	49 25	120 05	2200	6.7	10.0
NAREELAH C	54 08	128 32	920	6.6	6.0
NAKA CR	50 28	126 25	1400	9.9	31.0
NEMO CR	49 55	117 25	7100	6.3	3.0
NEWCASTLE	50 22	126 07	1300	6.6	15.0
NEXT CR	49 18	116 45	3000	4.8	22.0
NICOAMEN C	50 16	121 24	2200	3.4	10.0
NOEICK R	52 05	126 34	12200	4.6	N/A
NOEL CR	50 46	122 48	1160	6.8	2.0
NOOKLIKONN	52 22	126 34	4480	3.5	N/A
NOOMST CR	52 23	126 15	4070	5.0	N/A
NOOMST CR	52 26	126 13	1480	4.9	N/A
NOOSGULCH	52 26	126 23	1800	7.2	N/A
NOR/MID MF	50 11	125 47	1400	9.7	5.5
NORA CR	50 08	126 02	1200	6.9	22.0
NORDSCHOW	52 18	126 03	3790	4.2	N/A
OWL CR	50 22	122 44	2400	3.4	1.0
PACKSADDLE	52 48	119 08	1400	7.5	7.5
PALMERSTON	50 27	126 16	1100	7.5	28.0
PAYNE CR	50 37	117 51	1100	9.8	45.0
PERKETTS C	49 53	123 52	4500	2.6	15.0
PERRY R	49 54	126 37	1140	8.7	3.0
PHILLIPS C	49 40	125 34	2800	5.9	27.0

PIGGOTT CR	49 49	125 22	1200	3.6	14.0
POOL CR	50 47	117 38	6200	6.3	51.0
POPLAR CR	50 26	117 08	3600	9.8	17.0
POST CR	49 05	121 28	1020	5.8	17.0
POWDER CR	49 53	116 51	3600	6.8	23.0
PRETTY GIR	49 30	126 14	980	7.7	30.0
PTARMIGAN	52 35	118 50	4100	9.4	40.0
RAINY R	49 32	123 30	3070	4.8	3.0
RAPID CR	50 27	117 10	2500	7.0	21.0
RED TUSK C	49 47	123 25	3300	4.6	13.0
REINECKER	50 47	119 13	690	7.4	4.0
ROARING CR	49 27	122 13	2000	4.8	25.0
ROBSON R	53 03	119 13	2690	6.8	2.5
ROGERS CR	49 39	122 27	9100	2.8	1.0
ROSEWALL C	49 27	124 48	2100	3.2	1.0
RUBBLE CR	49 57	123 07	14700	2.9	4.0
SACHS CR	53 12	131 58	780	6.9	N/A
SALLOOMT C	52 27	126 32	1910	7.9	N/A
SALMON R	50 05	126 41	2700	4.8	19.0
SANCA CR	49 23	116 43	2000	4.7	1.0
SAUNDERS C	49 48	126 01	2000	5.3	2.0
SCHROEDER	50 02	116 55	1400	6.7	0.5
SCUZZZY CR	49 49	121 28	3900	6.1	3.0
SEASKINNIS	55 16	128 59	2330	6.4	2.0
SECHELT CR	49 40	123 33	6600	2.6	0.5
SEDAN CR	55 05	128 12	2030	5.9	8.0
SEPTET CR	50 48	116 41	1500	7.8	34.0
SHAMES R	54 25	128 54	1880	7.7	15.0
SHANNON CR	50 05	117 29	1900	5.6	2.0
SHANNON CR	54 40	127 30	1300	6.9	17.0
SHAW CR	49 15	116 43	1900	4.1	17.0
SHEPHERD C	49 38	125 31	1200	8.8	39.0
SICAMOUS C	50 48	118 58	2300	4.1	0.0
SIWASH CR	49 34	121 24	4200	3.9	12.0
SMALL CR	53 04	119 35	4000	7.3	7.0
SMITELY R	52 05	126 36	4100	6.0	N/A
SMITELY R	52 07	126 39	6300	3.8	N/A
SMYTH CR	50 32	118 43	1200	8.0	15.0
SNOOTLI CR	52 23	126 36	2420	3.7	N/A
SONGHEES C	50 47	127 35	990	8.7	8.0
SOUTH ENGL	49 15	124 17	3300	6.1	5.0
SOUTH CRAN	50 46	118 06	3800	2.9	6.0
SOWERBY CR	49 19	121 26	4100	3.1	7.0
SPUZZUM CR	49 39	121 26	2600	4.3	2.0
SQUAMISH R	50 10	123 24	11400	4.6	30.0
STAWAMUS C	49 42	123 07	5500	4.1	3.0
STE CROIX	54 42	128 19	1490	6.2	6.0
STIKELAN C	51 27	124 22	2100	9.1	N/A
SWAH CR	50 01	126 20	620	7.9	1.9
SWANEE CR	49 15	121 23	770	8.4	17.0
SWIFT CR #	52 52	119 13	2100	8.2	5.0
SWIFTCURRE	53 01	119 17	2550	5.8	0.5
TAHSISH R	50 13	127 03	1300	8.8	45.0
TAI A HAAT	54 46	130 04	660	9.8	5.0
TAM O'SHAN	49 48	116 51	3400	6.7	3.0
TANTALUS C	49 51	123 15	4900	4.4	2.0
TAQUAT CR	49 45	123 25	6700	2.7	11.0
TASTSQUAN	52 22	126 45	1200	3.2	N/A
TEMPLETON	50 48	116 29	1800	6.7	21.0
TENDERFOOT	50 28	117 13	2600	8.0	28.0

TEXAS CR	50	34	121	49	2700	4.4	13.0
TEXAS CR	50	31	121	50	1600	7.8	23.0
THELWOOD C	49	33	125	34	2100	6.4	41.0
THOMAS LAK	49	36	122	25	4100	4.3	50.0
THORNHILL	49	40	123	36	3970	2.5	0.0
THORSEN CR	52	21	126	42	3500	5.0	N/A
TIPELLA CR	49	45	122	10	3200	2.6	0.0
TLATLOS CR	50	23	126	14	2700	7.0	26.0
TLOOLS CR	49	52	125	45	1070	6.5	1.0
TLUPANA R	49	46	126	20	1900	8.1	2.0
TOMMY CR	50	50	122	31	2500	5.2	20.0
TOWN CR	50	46	117	45	1450	8.5	44.0
TRENT R	49	35	124	59	700	9.6	4.0
TRETHEWAY	49	42	122	05	1600	5.1	0.0
TROUT CR	54	51	127	19	570	7.7	0.0
TRUAX CR	50	53	122	38	1400	5.3	18.0
TSABLE R	49	31	124	54	2400	3.6	4.0
TSEAPSEAHO	52	26	126	24	2470	3.8	N/A
TSILEUH CR	49	46	121	26	4300	7.5	5.0
TSINI-TSIN	52	22	126	06	1790	4.8	N/A
TSUIUS CR	50	37	118	40	5300	4.6	7.0
TWENTYONE	50	07	122	59	2900	2.7	1.0
TWIN ONE C	50	15	122	30	6900	6.5	1.0
TZOONIE CR	49	47	123	43	2400	6.3	23.0
UCONA R	49	44	125	57	2300	3.1	10.0
UNNAMED CR	49	09	121	15	1570	6.7	30.0
UNNAMED CR	49	45	123	27	3500	2.9	11.0
UNNAMED CR	50	57	118	24	2500	3.4	6.0
UNNAMED CR	49	45	123	31	4800	2.0	6.0
UNNAMED CR	52	55	118	53	3450	2.8	11.0
UNNAMED CR	49	40	121	51	2500	6.7	55.0
UNNAMED CR	49	43	123	45	3200	3.5	17.0
UNNAMED CR	50	01	123	21	3500	2.9	15.0
UNNAMED CR	49	47	123	34	4600	3.5	17.0
UNNAMED CR	52	56	118	53	6800	3.1	11.0
UNNAMED CR	50	30	126	54	620	6.7	1.6
UNNAMED CR	49	29	121	25	1300	6.5	3.0
UNNAMED CR	52	10	126	50	8400	4.8	N/A
UNNAMED CR	50	58	118	36	1100	5.0	7.0
UNNAMED CR	49	41	123	35	1100	6.7	8.0
UNNAMED CR	54	05	129	56	820	5.9	12.0
UNNAMED CR	54	11	129	45	1300	5.9	10.0
UNNAMED CR	49	48	123	24	4280	5.4	13.0
UNNAMED CR	49	41	123	16	1770	4.6	2.5
UNNAMED CR	49	57	121	50	5800	5.3	28.0
UNNAMED CR	49	46	125	41	3500	4.1	20.0
UNNAMED CR	53	08	120	01	2240	6.9	23.0
UNNAMED CR	50	10	126	20	1300	5.6	13.0
UNNAMED CR	52	21	126	40	2800	5.4	N/A
UNNAMED CR	52	01	126	32	6280	4.3	N/A
UNNAMED CR	49	49	123	23	2200	4.3	17.0
UNNAMED CR	50	29	122	22	1500	5.9	8.0
UNNAMED CR	54	27	130	04	1180	5.8	30.0
UNNAMED CR	54	20	129	46	2000	4.3	16.0
UNNAMED CR	52	54	118	46	2700	4.0	24.0
UNNAMED CR	49	44	123	32	1300	3.8	5.0
UNNAMED CR	49	46	123	26	2090	3.8	14.0
UNNAMED CR	52	10	126	50	3500	3.8	N/A
UNNAMED CR	49	50	121	31	4300	5.2	9.0
UNNAMED CR	50	07	126	36	1400	6.4	9.0

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UNNAMED CR    50 55    118 07     1500     4.7     N/A
UNNAMED CR    49 45    123 43     2340     3.6    18.0
UNNAMED CR    54 23    128 53     1800     6.1    15.0
UNNAMED CR    50 29    127 21      770     6.9    10.0
UNNAMED CR    50 59    116 45     2000     5.2    28.0
UNNAMED CR    49 55    123 48     3650     6.1    25.0
UNNAMED CR    49 40    123 35     1140     6.2     0.0
UNNAMED CR    49 09    121 20     2000     6.8    30.0
UNNAMED CR    50 20    116 51      620     9.7    14.0
UNNAMED CR    54 22    128 54     1900     9.7    15.0
UNNAMED CR    49 57    126 51      380     9.6     N/A
UNNAMED CR    50 10    126 37     1300     7.6     7.0
UNNAMED CR    49 29    126 14      980     7.5    32.0
UNNAMED CR    49 59    116 03     1600     7.5    25.0
UNNAMED CR    49 15    121 15     1200     7.3    25.0
UNNAMED CR    49 12    121 20     1300     7.1    24.0
UNNAMED CR    50 10    126 18      940     7.1    14.0
UNNAMED CR    50 21    126 07     1000     7.5    19.0
UNNAMED CR    53 10    120 02     1830     7.4    18.0
UNNAMED CR    50 21    116 51     1000     7.4    15.0
UNNAMED CR    55 03    128 07     1140     9.3     3.3
UNNAMED CR    54 06    129 55     1250     8.3    12.0
UNNAMED CR    50 08    126 37      960     8.3    11.0
UNNAMED CR    50 29    126 24     1380     9.1    33.0
UNNAMED CR    54 05    128 20     1700     8.2    22.0
UNNAMED CR    54 10    129 56      490     7.8     0.5
UNNAMED CR    50 06    116 46      730     7.6     8.0
UNNAMED CR    50 05    126 28      980     9.5     1.2
UNNAMED CR    54 19    128 24      790     9.4    10.0
UNNAMED CR    50 07    116 44      770     7.7    13.0
UPANA CR      49 48    126 05     1300     9.0     0.1
URF CR        50 16    122 35    11800     3.3    10.0
VANCOUVER     49 56    123 48     3500     6.1    25.0
VICTOR CR     50 57    118 24     1100     4.7     6.0
WADY CR       50 24    127 17     1500     4.9    16.0
WALT LAKE     49 53    124 08      750     6.4    16.0
WARREN CR     50 58    116 42     5500     6.3    24.0
WEDGE CR      50 10    122 54     5500     2.6     2.0
WEE SANDY     50 00    117 25     2300     4.0    10.0
WHITE R       50 18    125 56     6300     4.0     2.0
WHITE CR      54 24    128 41     1390     6.8     8.0
WHITECAP C    50 43    122 18     1050     5.6     1.0
WILFRED CR    49 28    124 51      540     6.8     3.5
WILLIAMS C    54 24    128 25     3290     5.1     6.0
WILSON CR     49 35    116 52     2500     6.1    12.0
WILSON CR     50 08    117 20     3900     4.3    11.0
WILSON CR     55 03    128 17      950     8.4     5.0
WOODBURY C    49 48    116 57     4190     7.9     6.0
WRAGGE CR     50 04    117 28     1990     5.4     2.0
WRAY CR       49 20    121 18     1800     4.9    12.0
YARD CR       50 54    118 48     3290     4.9     0.0
YELLOWJACK    52 43    119 03     1400     6.6    17.0
YOUNG CR      52 25    125 53    18000     2.8     N/A
ZEBALLOS R    50 03    126 47     2400     5.2     N/A
ZEBALLOS L    50 03    126 46     3500     4.7     N/A
ZEBALLOS(L    49 59    126 45     2300     2.5     N/A
ZENITH CR     49 52    123 16      980     9.8    15.0

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APPENDIX 2

APPENDIX 2

SMALL HYDRO POWER CUMULATIVE CHARACTERISTICS VS EQUIVALENT NON-INFLATED COST PER KILOWATT-HOUR

Presented for:

1. All Sites
2. On-Grid Sites Only

Assumptions:

1. Operating costs @ 1.2% of capital costs per year for plant and transmission lines, but no less than $40,000 per year for any plant.
2. 50 year time horizon.
3. All construction costs incurred one year prior to first energy production for each site.
4. Transmission losses to grid and downtime reduce power output by 10%.
5. Water taxes not included.
6. Property and school taxes not included.
7. Costs of transmission to grid are included in capital cost where appropriate.
8. Cost per kW.h includes costs of operation and maintenance.
9. Contingency factor of 30%. Assumed to include land cost, interconnection to grid where appropriate.
10. No real inflation of operating costs.
11. Average cost per kW.h includes all sites up to a given cost per kW.h.
12. No sharing of transmission line for nearby sites.
13. Project management overhead of 8% of capital costs.
14. Discount rate of 8%.

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CAPACITIES REDUCED BY FIRM FEES, DOWN TIME AND TRANSMISSION LINE LOSSES
MEAN    DISCOUNT RATE - 8 %    OPERATION AND MAINTENANCE RATE - 1.2 %           MANAGEMENT FEE   8 %             ALL SITES (Page 1 of 2)
WATER TAXES ARE NOT INCLUDED.  TRANSMISSION COST FACTOR NOT INCLUDED

 COST C/KWH   # SITES  MEAN CAP.    ENERGY    TOTAL # SITES  INSTALLED CAPACITY  CUM. MEAN CAP.    CUM. ENERGY    AV. COST/KWH   CUM. CAP. COST
                          KW        GWH/YR                          KW                KW            GWH/YR        C/KWH        ($1,000,000)

 0.0  TO  0.1    0          0          0            0                   0                 0                0          0.00             0
 0.1  TO  0.2    0          0          0            0                   0                 0                0          0.00             0
 0.2  TO  0.3    0          0          0            0                   0                 0                0          0.00             0
 0.3  TO  0.4    0          0          0            0                   0                 0                0          0.00             0
 0.4  TO  0.5    0          0          0            0                   0                 0                0          0.00             0
 0.5  TO  0.6    0          0          0            0                   0                 0                0          0.00             0
 0.6  TO  0.7    0          0          0            0                   0                 0                0          0.00             0
 0.7  TO  0.8    0          0          0            0                   0                 0                0          0.00             0
 0.8  TO  0.9    0          0          0            0                   0                 0                0          0.00             0
 0.9  TO  1.0    0          0          0            0                   0                 0                0          0.00             0
 1.0  TO  1.1    0          0          0            0                   0                 0                0          0.00             0
 1.1  TO  1.2    0          0          0            0                   0                 0                0          0.00             0
 1.2  TO  1.3    0          0          0            0                   0                 0                0          0.00             0
 1.3  TO  1.4    0          0          0            0                   0                 0                0          0.00             0
 1.4  TO  1.5    0          0          0            0                   0                 0                0          0.00             0
 1.5  TO  1.6    0          0          0            0                   0                 0                0          0.00             0
 1.6  TO  1.7    0          0          0            0                   0                 0                0          0.00             0
 1.7  TO  1.8    1      3,020         26            1                4660             3,020               26          1.75             5
 1.8  TO  1.9    1     14,723        129            2               28700            17,743              155          1.82            30
 1.9  TO  2.0    2      4,658         41            4                8700            22,400              196          1.86            39
 2.0  TO  2.1    0          0          0            4                   0            22,400              196          1.86            39
 2.1  TO  2.2    0          0          0            4                   0            22,400              196          1.86            39
 2.2  TO  2.3    0          0          0            4                   0            22,400              196          1.86            39
 2.3  TO  2.4    3     18,958        166            7               36200            41,358              362          2.07            80
 2.4  TO  2.5    2      5,678         50            9               11470            47,036              412          2.11            93
 2.5  TO  2.6    4     10,558         92           13               20200            57,593              505          2.20           118
 2.6  TO  2.7    6     20,253        177           19               35990            77,846              682          2.32           169
 2.7  TO  2.8    4     19,947        175           23               35100            97,793              857          2.41           220
 2.8  TO  2.9    9     26,923        236           32               51290           124,716            1,093          2.51           292
 2.9  TO  3.0    0          0          0           32                   0           124,716            1,093          2.51           292
 3.0  TO  3.1    2      5,511         48           34               10990           130,227            1,141          2.53           308
 3.1  TO  3.2    4      6,656         58           38               12260           136,884            1,199          2.56           327
 3.2  TO  3.3    8     16,453        144           46               32300           153,337            1,343          2.64           377
 3.3  TO  3.4    2      4,406         39           48                8300           157,742            1,382          2.66           391
 3.4  TO  3.5   13     22,802        200           61               43240           180,544            1,582          2.75           464
 3.5  TO  3.6    3     14,255        125           64               26220           194,799            1,706          2.81           511
 3.6  TO  3.7    5      7,592         67           69               15600           202,391            1,773          2.84           537
 3.7  TO  3.8    6     12,358        108           75               22610           214,750            1,881          2.89           580
 3.8  TO  3.9    7     12,866        113           82               24370           227,616            1,994          2.95           626
 3.9  TO  4.0    3      8,610         75           85               17900           236,226            2,069          2.98           658
 4.0  TO  4.1   12     29,010        254           97               55490           265,236            2,323          3.10           768
 4.1  TO  4.2    3      3,755         33          100                7680           268,991            2,356          3.12           782
 4.2  TO  4.3    5     10,205         89          105               18570           279,196            2,446          3.16           823
 4.3  TO  4.4    7     10,675         94          112               21480           289,870            2,539          3.20           866
 4.4  TO  4.5    3      4,896         43          115                9700           294,766            2,582          3.22           886
 4.5  TO  4.6    8     18,691        164          123               35530           313,457            2,746          3.30           965
 4.6  TO  4.7   10     22,238        195          133               43770           335,695            2,941          3.39          1061
 4.7  TO  4.8    9     20,651        181          142               39120           356,346            3,122          3.47          1153
 4.8  TO  4.9    8     15,029        132          150               31590           371,375            3,253          3.53          1221
 4.9  TO  5.0    6      6,642         58          156               13920           378,017            3,311          3.55          1252
 5.0  TO  5.1    9     17,876        157          165               33870           395,894            3,468          3.62          1336
 5.1  TO  5.2    7      7,712         68          172               15480           403,605            3,536          3.65          1373
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(Page 2 of 2)

5.2	TO	5.3	4	6,474	56	176	14560	410,031	3,552	3.67	[illegible]
5.3	TO	5.4	3	12,025	111	177	23400	422,056	3,702	3.72	[illegible]
5.4	TO	5.5	6	6,755	59	185	13360	428,811	3,762	3.75	1501
5.5	TO	5.6	3	2,644	18	188	4250	431,455	3,780	3.76	1511
5.6	TO	5.7	3	6,788	59	191	13220	438,243	3,839	3.79	1547
5.7	TO	5.8	4	3,436	30	195	6450	441,679	3,869	3.80	1565
5.8	TO	5.9	7	7,364	65	202	14630	449,043	3,934	3.84	1605
5.9	TO	6.0	5	8,526	75	207	14630	457,569	4,008	3.88	1653
6.0	TO	6.1	5	6,251	55	212	13570	463,820	4,063	3.90	1688
6.1	TO	6.2	7	9,855	86	221	20050	473,674	4,149	3.95	1744
6.2	TO	6.3	4	7,695	67	225	17290	481,369	4,217	3.99	1789
6.3	TO	6.4	11	13,967	122	236	28850	495,336	4,339	4.05	1872
6.4	TO	6.5	4	5,414	47	240	10650	500,750	4,387	4.08	1904
6.5	TO	6.6	6	4,228	37	246	7310	504,979	4,424	4.10	1930
6.6	TO	6.7	11	10,416	91	257	22120	515,395	4,515	4.15	1994
6.7	TO	6.8	12	14,361	126	269	30840	529,756	4,641	4.22	2085
6.8	TO	6.9	8	6,282	55	277	11910	536,038	4,696	4.25	2125
6.9	TO	7.0	7	6,667	58	284	13940	542,705	4,754	4.29	2167
7.0	TO	7.1	7	6,514	57	291	11390	549,220	4,811	4.32	2210
7.1	TO	7.2	7	12,443	109	298	26940	561,662	4,920	4.38	2293
7.2	TO	7.3	7	4,652	41	305	9370	566,314	4,961	4.41	2325
7.3	TO	7.4	3	3,955	35	308	8560	570,269	4,996	4.43	2352
7.4	TO	7.5	10	7,125	62	318	15260	577,393	5,058	4.46	2400
7.5	TO	7.6	4	3,028	27	322	5600	580,421	5,084	4.48	2422
7.6	TO	7.7	6	5,288	46	328	9360	585,709	5,131	4.51	2459
7.7	TO	7.8	7	6,951	61	335	13760	592,660	5,192	4.55	2509
7.8	TO	7.9	5	3,530	31	340	6360	596,190	5,223	4.57	2535
7.9	TO	8.0	6	4,599	40	346	9430	600,789	5,263	4.59	2569
8.0	TO	8.1	4	3,149	28	350	6280	603,939	5,291	4.61	2592
8.1	TO	8.2	3	3,633	32	353	6990	607,572	5,322	4.63	2620
8.2	TO	8.3	7	5,648	49	360	11490	613,220	5,372	4.67	2663
8.3	TO	8.4	5	3,642	32	365	8020	616,862	5,404	4.69	2692
8.4	TO	8.5	2	1,127	10	367	2050	617,989	5,414	4.69	2700
8.5	TO	8.6	5	5,040	44	372	9490	623,028	5,458	4.73	2741
8.6	TO	8.7	3	2,149	19	375	4300	625,177	5,477	4.74	2758
8.7	TO	8.8	4	2,967	26	379	5180	628,144	5,503	4.76	2782
8.8	TO	8.9	4	2,907	25	383	5030	631,050	5,528	4.78	2806
8.9	TO	9.0	1	761	7	384	1300	631,811	5,535	4.78	2812
9.0	TO	9.1	4	4,444	39	388	9380	636,255	5,574	4.81	2850
9.1	TO	9.2	1	1,260	11	389	2800	637,515	5,585	4.82	2861
9.2	TO	9.3	2	1,746	15	391	3510	639,261	5,600	4.83	2876
9.3	TO	9.4	1	754	7	392	1250	640,015	5,607	4.84	2882
9.4	TO	9.5	3	2,620	23	395	5750	642,635	5,629	4.86	2905
9.5	TO	9.6	4	2,318	20	399	4250	644,952	5,650	4.87	2926
9.6	TO	9.7	3	3,139	27	402	6680	648,092	5,677	4.90	2954
9.7	TO	9.8	5	2,906	25	407	5880	650,998	5,703	4.92	2980
9.8	TO	9.9	5	3,884	34	412	8010	654,882	5,737	4.95	3016
9.9	TO	10.0	1	806	7	413	1400	655,688	5,744	4.95	3023
10.0	TO	10.1	6	3,295	29	419	7560	658,983	5,773	4.98	3054

CAPACITIES REDUCED BY FIRMNESS, DOWN TIME AND TRANSMISSION LINE LOSSES
GRID DISCOUNT RATE - 3 % OPERATION AND MAINTENANCE RATE - 1.2 % MANAGEMENT FEE - 8 %
WATER TAXES ARE NOT INCLUDED, TRANSMISSION COST FACTOR NOT INCLUDED

ON-GRID SITES (1st of 2 pages)

COST C/KWH	# SITES	CAPACITY KW	CAPACITY GWH	TOTAL # SITES	INSTALLED CAPACITY KW	POWER CAPACITY KW	TOTAL CAPACITY GWH	AV. COST/KWH C/KWH	CUM. CAP. COST ($1,000,000)
0.0 TO 0.1	0	0	0	0	0	0	0	0.00	0
0.1 TO 0.2	0	0	0	0	0	0	0	0.00	0
0.2 TO 0.3	0	0	0	0	0	0	0	0.00	0
0.3 TO 0.4	0	0	0	0	0	0	0	0.00	0
0.4 TO 0.5	0	0	0	0	0	0	0	0.00	0
0.5 TO 0.6	0	0	0	0	0	0	0	0.00	0
0.6 TO 0.7	0	0	0	0	0	0	0	0.00	0
0.7 TO 0.8	0	0	0	0	0	0	0	0.00	0
0.8 TO 0.9	0	0	0	0	0	0	0	0.00	0
0.9 TO 1.0	0	0	0	0	0	0	0	0.00	0
1.0 TO 1.1	0	0	0	0	0	0	0	0.00	0
1.1 TO 1.2	0	0	0	0	0	0	0	0.00	0
1.2 TO 1.3	0	0	0	0	0	0	0	0.00	0
1.3 TO 1.4	0	0	0	0	0	0	0	0.00	0
1.4 TO 1.5	0	0	0	0	0	0	0	0.00	0
1.5 TO 1.6	0	0	0	0	0	0	0	0.00	0
1.6 TO 1.7	0	0	0	0	0	0	0	0.00	0
1.7 TO 1.8	0	0	0	0	0	0	0	0.00	0
1.8 TO 1.9	1	14,723	129	1	28700	14,723	129	1.84	25
1.9 TO 2.0	2	4,658	41	3	8700	19,381	170	1.87	34
2.0 TO 2.1	0	0	0	3	0	19,381	170	1.87	34
2.1 TO 2.2	0	0	0	3	0	19,381	170	1.87	34
2.2 TO 2.3	0	0	0	3	0	19,381	170	1.87	34
2.3 TO 2.4	2	12,815	112	5	25700	32,196	282	2.05	62
2.4 TO 2.5	2	5,678	50	7	11470	37,873	332	2.11	75
2.5 TO 2.6	3	9,212	81	10	17900	47,086	412	2.20	97
2.6 TO 2.7	6	20,253	177	16	35990	67,338	590	2.34	147
2.7 TO 2.8	3	9,417	82	19	17100	76,756	672	2.39	172
2.8 TO 2.9	7	22,600	198	26	43900	99,356	870	2.50	232
2.9 TO 3.0	0	0	0	26	0	99,356	870	2.50	232
3.0 TO 3.1	2	5,511	48	28	10990	104,867	919	2.53	248
3.1 TO 3.2	3	5,954	52	31	11060	110,821	971	2.56	265
3.2 TO 3.3	8	16,453	144	39	32300	127,274	1,115	2.65	315
3.3 TO 3.4	2	4,406	39	41	8300	131,679	1,154	2.67	329
3.4 TO 3.5	12	20,975	184	53	40340	152,654	1,337	2.78	396
3.5 TO 3.6	2	11,634	102	55	21740	164,288	1,439	2.83	434
3.6 TO 3.7	5	7,592	67	60	15600	171,881	1,506	2.87	460
3.7 TO 3.8	3	7,199	63	63	13790	179,079	1,569	2.90	485
3.8 TO 3.9	5	7,619	67	68	15400	186,698	1,635	2.94	513
3.9 TO 4.0	3	8,610	75	71	17900	195,308	1,711	2.99	544
4.0 TO 4.1	11	26,612	233	82	51390	221,920	1,944	3.12	645
4.1 TO 4.2	3	3,755	33	85	7680	225,675	1,977	3.13	660
4.2 TO 4.3	3	4,314	38	88	8500	229,988	2,015	3.15	677
4.3 TO 4.4	7	10,675	94	95	21480	240,663	2,108	3.21	720
4.4 TO 4.5	3	4,896	43	98	9700	245,559	2,151	3.23	741
4.5 TO 4.6	7	11,554	101	105	23330	257,113	2,252	3.29	789
4.6 TO 4.7	9	21,630	189	114	42270	278,743	2,442	3.40	883
4.7 TO 4.8	7	13,690	120	121	27220	292,433	2,562	3.46	943
4.8 TO 4.9	5	11,097	97	126	24870	303,530	2,659	3.51	993
4.9 TO 5.0	6	6,642	58	132	13920	310,173	2,717	3.54	1024
5.0 TO 5.1	6	8,858	78	138	17800	319,031	2,795	3.56	1066

ON-GRID SITES
(2nd of 2 pages)

5.1	TO	5.2	5	5,321	48	143	11490	324,551	2,643	3.61
5.2	TO	5.3	3	5,208	46	146	12100	329,760	2,689	3.64
5.3	TO	5.4	2	1,825	16	148	3400	331,585	2,705	3.64
5.4	TO	5.5	5	5,117	45	153	10560	336,702	2,950	3.67
5.5	TO	5.6	3	2,044	18	156	4250	338,746	2,967	3.68
5.6	TO	5.7	3	6,788	59	159	13220	345,533	3,027	3.72
5.7	TO	5.8	4	3,436	30	163	6450	348,970	3,057	3.74
5.8	TO	5.9	6	6,980	61	169	14020	355,949	3,118	3.78
5.9	TO	6.0	4	6,127	54	173	10530	362,076	3,172	3.82
6.0	TO	6.1	5	6,251	55	178	13570	368,327	3,227	3.86
6.1	TO	6.2	9	9,855	86	187	20050	378,182	3,313	3.92
6.2	TO	6.3	4	7,695	67	191	17290	385,877	3,380	3.96
6.3	TO	6.4	11	13,967	122	202	23850	399,844	3,503	4.05
6.4	TO	6.5	4	5,414	47	206	10650	405,258	3,550	4.08
6.5	TO	6.6	6	4,228	37	212	9310	409,486	3,587	4.11
6.6	TO	6.7	11	10,416	91	223	22120	419,902	3,678	4.17
6.7	TO	6.8	12	14,361	126	235	30840	434,263	3,804	4.25
6.8	TO	6.9	7	5,826	51	242	11130	440,089	3,855	4.29
6.9	TO	7.0	7	6,667	58	249	13940	446,757	3,914	4.33
7.0	TO	7.1	7	6,514	57	256	11390	453,271	3,971	4.37
7.1	TO	7.2	5	7,218	63	261	14849	460,489	4,034	4.41
7.2	TO	7.3	5	4,023	35	266	8100	464,512	4,069	4.44
7.3	TO	7.4	3	3,955	35	269	8560	468,467	4,104	4.46
7.4	TO	7.5	10	7,125	62	279	15260	475,591	4,166	4.50
7.5	TO	7.6	4	3,028	27	283	5600	478,619	4,193	4.52
7.6	TO	7.7	6	5,288	46	289	9360	483,907	4,239	4.56
7.7	TO	7.8	7	6,951	61	296	13760	490,858	4,300	4.60
7.8	TO	7.9	4	2,412	21	300	4450	493,271	4,321	4.62
7.9	TO	8.0	6	4,599	40	306	7430	497,870	4,361	4.65
8.0	TO	8.1	4	3,149	28	310	6280	501,019	4,389	4.67
8.1	TO	8.2	3	3,633	32	313	6990	504,653	4,421	4.70
8.2	TO	8.3	7	5,647	49	320	11490	510,300	4,470	4.74
8.3	TO	8.4	5	3,642	32	325	8020	513,943	4,502	4.76
8.4	TO	8.5	2	1,127	10	327	2050	515,069	4,512	4.77
8.5	TO	8.6	4	3,834	34	331	7430	518,904	4,546	4.80
8.6	TO	8.7	3	2,149	19	334	4300	521,053	4,564	4.81
8.7	TO	8.8	4	2,967	26	338	5180	524,019	4,590	4.84
8.8	TO	8.9	3	1,836	16	341	3200	525,855	4,606	4.85
8.9	TO	9.0	1	760	7	342	1300	526,616	4,613	4.86
9.0	TO	9.1	3	3,594	31	345	7280	530,210	4,645	4.88
9.1	TO	9.2	1	1,260	11	346	2800	531,470	4,656	4.89
9.2	TO	9.3	2	1,746	15	348	3510	533,216	4,671	4.91
9.3	TO	9.4	1	754	7	349	1250	533,969	4,678	4.91
9.4	TO	9.5	3	2,620	23	352	5750	536,589	4,701	4.94
9.5	TO	9.6	4	2,318	20	356	4250	538,907	4,721	4.96
9.6	TO	9.7	2	2,917	26	358	6300	541,824	4,746	4.98
9.7	TO	9.8	5	2,906	25	363	5880	544,730	4,772	5.01
9.8	TO	9.9	4	3,241	28	367	6910	547,971	4,800	5.04
9.9	TO	10.0	1	806	7	368	1400	548,777	4,807	5.04
10.0	TO	10.1	5	2,471	22	373	5090	551,248	4,829	5.07

5.1 TO 5.2	1072
5.2 TO 5.3	1117
5.3 TO 5.4	1126
5.4 TO 5.5	1152
5.5 TO 5.6	1163
5.6 TO 5.7	1198
5.7 TO 5.8	1217
5.8 TO 5.9	1255
5.9 TO 6.0	1288
6.0 TO 6.1	1324
6.1 TO 6.2	1380
6.2 TO 6.3	1425
6.3 TO 6.4	1507
6.4 TO 6.5	1540
6.5 TO 6.6	1565
6.6 TO 6.7	1630
6.7 TO 6.8	1721
6.8 TO 6.9	1757
6.9 TO 7.0	1800
7.0 TO 7.1	1843
7.1 TO 7.2	1891
7.2 TO 7.3	1918
7.3 TO 7.4	1945
7.4 TO 7.5	1994
7.5 TO 7.6	2016
7.6 TO 7.7	2053
7.7 TO 7.8	2103
7.8 TO 7.9	2121
7.9 TO 8.0	2154
8.0 TO 8.1	2178
8.1 TO 8.2	2206
8.2 TO 8.3	2249
8.3 TO 8.4	2277
8.4 TO 8.5	2286
8.5 TO 8.6	2316
8.6 TO 8.7	2334
8.7 TO 8.8	2358
8.8 TO 8.9	2373
8.9 TO 9.0	2379
9.0 TO 9.1	2410
9.1 TO 9.2	2421
9.2 TO 9.3	2436
9.3 TO 9.4	2442
9.4 TO 9.5	2465
9.5 TO 9.6	2486
9.6 TO 9.7	2512
9.7 TO 9.8	2538
9.8 TO 9.9	2568
9.9 TO 10.0	2576
10.0 TO 10.1	2599

APPENDIX 3

APPENDIX 3

PEACE SITE C COST ANALYSIS

Presented for:

1. Assumption that there is a market for all available power.
2. Assuming that power is sold only to meet domestic demand.

Assumptions:

1. Discount rate of 8 percent.
2. Costs are in October 1982 dollars.
3. Costs and capacities supplied by BC Hydro (Jan 1983).
4. Load growth forecast based on MEMPR forecast (Reference 6).
5. 50 year time horizon.
6. In-service date of February 1991.
7. Water taxes not included.
8. Property and school taxes not included.

1. Power Cost for Site C Assuming Sale of all Power

**** POWER COST ANALYSIS FOR PEACE SITE C ****

DISCOUNT RATE = 8.00 VALUE OF EXPORT POWER (MILLS/KWH) = .00

CONSTRUCTION MANAGEMENT COSTS (%) = 5.00

YEAR	DOMESTIC POWER (GWH/YR)	EXPORT POWER (GWH)	TOTAL POWER (GWH)	DISCOUNTED DOMESTIC POWER (GWH)	VALUE EXPORT POWER ($M)	PV VALUE EXPORT POWER ($M)	CONSTRUCTION COSTS GENERATION ($M)	TRANSMISSION ($M)	TOTAL ($M)	PV ($M)	OPERATION AND MAINTENANCE ($M)	PV OPER. AND MAINT. ($M)
1982	.00	.00	.00	.00	.00	.00	41.50	1.10	42.40	42.60		.00
1983	.00	.00	.00	.00	.00	.00	3.74	.24	4.18	3.87		.00
1984	.00	.00	.00	.00	.00	.00	33.91	.31	35.94	30.81		.00
1985	.00	.00	.00	.00	.00	.00	114.50	1.59	121.89	96.76		.00
1986	.00	.00	.00	.00	.00	.00	158.65	7.15	174.08	127.96		.00
1987	.00	.00	.00	.00	.00	.00	135.91	9.71	152.90	104.06		.00
1988	.00	.00	.00	.00	.00	.00	263.95	28.15	306.71	193.28		.00
1989	.00	.00	.00	.00	.00	.00	349.61	61.01	431.14	251.57		.00
1990	.00	.00	.00	.00	.00	.00	247.25	44.35	306.17	165.41		.00
1991	3295.00	.00	3295.00	1648.32	.00	.00	34.72	11.32	48.33	24.18	6.70	3.62
1992	4770.00	.00	4770.00	2209.43	.00	.00	3.20	.00	3.36	1.56	6.70	3.35
1993	4770.00	.00	4770.00	2045.77	.00	.00	.90	.00	.95	.41	6.70	3.10
1994	4770.00	.00	4770.00	1894.23	.00	.00	.00	.00	.00	.00	6.70	2.87
1995	4770.00	.00	4770.00	1753.92	.00	.00	.00	.00	.00	.00	6.70	2.66
1996	4770.00	.00	4770.00	1624.00	.00	.00	.00	.00	.00	.00	6.70	2.46
1997	4770.00	.00	4770.00	1503.70	.00	.00	.00	.00	.00	.00	6.70	2.28
1998	4770.00	.00	4770.00	1392.32	.00	.00	.00	.00	.00	.00	6.70	2.11
1999	4770.00	.00	4770.00	1289.18	.00	.00	.00	.00	.00	.00	6.70	1.96
2000	4770.00	.00	4770.00	1193.69	.00	.00					6.70	1.81
2001	4770.00	.00	4770.00	1105.27	.00	.00					6.70	1.68
2002	4770.00	.00	4770.00	1023.39	.00	.00					6.70	1.55
2003	4770.00	.00	4770.00	947.59	.00	.00					6.70	1.44
2004	4770.00	.00	4770.00	877.40	.00	.00					6.70	1.33
2005	4770.00	.00	4770.00	812.40	.00	.00					6.70	1.23
2006	4770.00	.00	4770.00	752.23	.00	.00					6.70	1.14
2007	4770.00	.00	4770.00	696.51	.00	.00					6.70	1.06
2008	4770.00	.00	4770.00	644.91	.00	.00					6.70	.98
2009	4770.00	.00	4770.00	597.14	.00	.00					6.70	.91
2010	4770.00	.00	4770.00	552.91	.00	.00					6.70	.84
2011	4770.00	.00	4770.00	511.95	.00	.00					6.70	.78
2012	4770.00	.00	4770.00	474.03	.00	.00					6.70	.72
2013	4770.00	.00	4770.00	438.92	.00	.00					6.70	.67
2014	4770.00	.00	4770.00	406.40	.00	.00					6.70	.62
2015	4770.00	.00	4770.00	376.30	.00	.00					6.70	.57
2016	4770.00	.00	4770.00	348.43	.00	.00					6.70	.53
2017	4770.00	.00	4770.00	322.62	.00	.00					6.70	.49
2018	4770.00	.00	4770.00	298.72	.00	.00					6.70	.45
2019	4770.00	.00	4770.00	276.59	.00	.00					6.70	.42
2020	4770.00	.00	4770.00	256.10	.00	.00					6.70	.39
2021	4770.00	.00	4770.00	237.13	.00	.00					6.70	.36
2022	4770.00	.00	4770.00	219.57	.00	.00					6.70	.33
2023	4770.00	.00	4770.00	203.30	.00	.00					6.70	.31
2024	4770.00	.00	4770.00	188.24	.00	.00					6.70	.29
2025	4770.00	.00	4770.00	174.30	.00	.00					6.70	.26
2026	4770.00	.00	4770.00	161.39	.00	.00					6.70	.24
2027	4770.00	.00	4770.00	149.43	.00	.00					6.70	.23
2028	4770.00	.00	4770.00	138.36	.00	.00					6.70	.21
2029	4770.00	.00	4770.00	128.12	.00	.00					6.70	.19
2030	4770.00	.00	4770.00	118.63	.00	.00					6.70	.18
2031	4770.00	.00	4770.00	109.84	.00	.00					6.70	.17
2032	4770.00	.00	4770.00	101.70	.00	.00					6.70	.15
											6.70	.14

```
2033  4770.00     .00  4770.00      94.17       .00    .00                                          6.70    .13
2034  4770.00     .00  4770.00      87.19       .00    .00                                          6.70    .12
2035  4770.00     .00  4770.00      80.73       .00    .00                                          6.70    .11
2036  4770.00     .00  4770.00      74.75       .00    .00                                          6.70    .11
2037  4770.00     .00  4770.00      69.72       .00    .00                                          6.70    .10
2038  4770.00     .00  4770.00      64.09       .00    .00                                          6.70    .09
2039  4770.00     .00  4770.00      59.34       .00    .00                                          6.70    .06
                                 --------          --------  --------  --------  --------  --------          --------
TOTALS =                         26354.70               .00   1387.82    164.91   1678.24   1042.45             47.83
                                 ========          ========  ========  ========  ========  ========          ========


PV NET COST OF DOMESTIC POWER:
  PV CAPITAL COSTS               1042.45
  PLUS PV O & M COSTS              47.83
  LESS PV EXPORT POWER               .00
                                 --------
                                 1090.28        PV COST OF DOMESTIC POWER PER KWH = PV NET COST / DISCOUNTED DOMESTIC POWER
                                 ========
                                                                        =            41.37 MILLS
                                                                                  ================
```

2. Power Cost of Site C Assuming Sale of Power for Domestic Demand Only

**** POWER COST ANALYSIS FOR PEACE SITE C ****

DISCOUNT RATE = 8.00 VALUE OF EXPORT POWER (MILLS/KWH) = .00

CONSTRUCTION MANAGEMENT COSTS (%) = 5.00

YEAR	DOMESTIC POWER (GWH/YR)	EXPORT POWER (GWH)	TOTAL POWER (GWH)	DISCOUNTED DOMESTIC POWER (GWH)	VALUE EXPORT POWER ($M)	PV VALUE EXPORT POWER ($M)	CONSTRUCTION COSTS GENERATION ($M)	TRANSMISSION ($M)	TOTAL ($M)	PV ($M)	OPERATION AND MAINTENANCE ($M)	PV OPER. AND MAINT. ($M)
1982	.00	.00	.00	.00	.00	.00	41.50	1.10	42.60	42.60		.00
1983	.00	.00	.00	.00	.00	.00	3.74	.24	4.18	3.87		.00
1984	.00	.00	.00	.00	.00	.00	33.91	.31	35.94	30.81		.00
1985	.00	.00	.00	.00	.00	.00	114.50	1.59	121.89	96.76		.00
1986	.00	.00	.00	.00	.00	.00	158.65	7.15	174.08	127.96		.00
1987	.00	.00	.00	.00	.00	.00	135.91	9.71	152.90	104.06		.00
1988	.00	.00	.00	.00	.00	.00	261.95	28.15	306.71	193.28		.00
1989	.00	.00	.00	.00	.00	.00	349.61	61.01	431.14	251.57		.00
1990	.00	.00	.00	.00	.00	.00	247.25	44.35	306.17	165.41	6.70	3.62
1991	1111.00	2184.00	3295.00	555.78	.00	.00	34.77	11.32	48.33	24.18	6.70	3.35
1992	1944.00	2826.00	4770.00	900.45	.00	.00	3.20	.00	3.36	1.56	6.70	3.10
1993	2500.00	2270.00	4770.00	1072.21	.00	.00	.90	.00	.95	.41	6.70	2.87
1994	3056.00	1714.00	4770.00	1213.58	.00	.00	.00	.00	.00	.00	6.70	2.66
1995	3889.00	881.00	4770.00	1429.98	.00	.00	.00	.00	.00	.00	6.70	2.46
1996	4770.00	.00	4770.00	1624.00	.00	.00	.00	.00	.00	.00	6.70	2.28
1997	4770.00	.00	4770.00	1503.70	.00	.00	.00	.00	.00	.00	6.70	2.11
1998	4770.00	.00	4770.00	1392.32	.00	.00	.00	.00	.00	.00	6.70	1.96
1999	4770.00	.00	4770.00	1289.18	.00	.00					6.70	1.81
2000	4770.00	.00	4770.00	1193.69	.00	.00					6.70	1.68
2001	4770.00	.00	4770.00	1105.27	.00	.00					6.70	1.55
2002	4770.00	.00	4770.00	1023.39	.00	.00					6.70	1.44
2003	4770.00	.00	4770.00	947.59	.00	.00					6.70	1.33
2004	4770.00	.00	4770.00	877.40	.00	.00					6.70	1.23
2005	4770.00	.00	4770.00	812.40	.00	.00					6.70	1.14
2006	4770.00	.00	4770.00	752.23	.00	.00					6.70	1.06
2007	4770.00	.00	4770.00	696.51	.00	.00					6.70	.98
2008	4770.00	.00	4770.00	644.91	.00	.00					6.70	.91
2009	4770.00	.00	4770.00	597.14	.00	.00					6.70	.84
2010	4770.00	.00	4770.00	552.91	.00	.00					6.70	.78
2011	4770.00	.00	4770.00	511.95	.00	.00					6.70	.72
2012	4770.00	.00	4770.00	474.03	.00	.00					6.70	.67
2013	4770.00	.00	4770.00	438.92	.00	.00					6.70	.62
2014	4770.00	.00	4770.00	406.40	.00	.00					6.70	.57
2015	4770.00	.00	4770.00	376.30	.00	.00					6.70	.53
2016	4770.00	.00	4770.00	348.43	.00	.00					6.70	.49
2017	4770.00	.00	4770.00	322.62	.00	.00					6.70	.45
2018	4770.00	.00	4770.00	298.72	.00	.00					6.70	.42
2019	4770.00	.00	4770.00	276.59	.00	.00					6.70	.39
2020	4770.00	.00	4770.00	256.10	.00	.00					6.70	.36
2021	4770.00	.00	4770.00	237.13	.00	.00					6.70	.33
2022	4770.00	.00	4770.00	219.57	.00	.00					6.70	.31
2023	4770.00	.00	4770.00	203.30	.00	.00					6.70	.29
2024	4770.00	.00	4770.00	188.24	.00	.00					6.70	.26
2025	4770.00	.00	4770.00	174.30	.00	.00					6.70	.24
2026	4770.00	.00	4770.00	161.39	.00	.00					6.70	.23
2027	4770.00	.00	4770.00	149.43	.00	.00					6.70	.21
2028	4770.00	.00	4770.00	138.36	.00	.00					6.70	.19
2029	4770.00	.00	4770.00	128.12	.00	.00					6.70	.18
2030	4770.00	.00	4770.00	118.63	.00	.00					6.70	.17
2031	4770.00	.00	4770.00	109.84	.00	.00					6.70	.15
2032	4770.00	.00	4770.00	101.70	.00	.00					6.70	.14

```
2033  4770.00     .00  4770.00          74.17          .00      .00                                                  6.70     .13
2034  4770.00     .00  4770.00          87.19          .00      .00                                                  6.70     .12
2035  4770.00     .00  4770.00          80.73          .00      .00                                                  6.70     .11
2036  4770.00     .00  4770.00          74.75          .00      .00                                                  6.70     .11
2037  4770.00     .00  4770.00          69.72          .00      .00                                                  6.70     .10
2038  4770.00     .00  4770.00          64.09          .00      .00                                                  6.70     .09
2039  4770.00     .00  4770.00          59.34          .00      .00                                                  6.70     .08
                                     --------               --------   --------  ---------  --------  --------           --------
TOTALS =                             30733.89                    .00    1387.87     164.91   1678.24   1042.45              47.83
                                     ========               ========   ========  =========  ========  ========           ========


PV NET COST OF DOMESTIC POWER:
  PV CAPITAL COSTS                    1042.45
  PLUS PV O & M COSTS                   47.83
  LESS PV EXPORT POWER                    .00
                                     --------
                                      1090.28        PV COST OF DOMESTIC POWER PER KWH = PV NET COST / DISCOUNTED DOMESTIC POWER
                                     ========
                                                                       =           35.47 MILLS
                                                                                   ===============
```

APPENDIX 4

APPENDIX 4

DETAILED CAPITAL COSTING METHODOLOGY

This model was programmed on a "Supercalc" computerized worksheet for the **Resource Assessment** (Reference 1). Its purpose was to assess the costs and capacities of the selected small hydro power sites. This model required 12 input variables as described below:

Intake Elevation (in metres) - from topographic mapping

Powerhouse Elevation (in metres) - from topographic mapping

Design Flow (in cubic metres/sec) - estimated mean annual flow (MAF) was used as this was generally found to be the most optimum point, although the range from 60 percent MAF to 200 percent MAF is generally acceptable

Horizontal Penstock Length (metres) - measured penstock length from topographic mapping

Site Factor - a factor applied to the costs of certain items to account for the remoteness/accessibility of the small hydro site. A factor of 1.0 would be applied for sites around areas like Vancouver and a factor of up to 1.5 could be applied for remote areas such as the Queen Charlotte Islands.

Access Road Length - length of access road required to reach the power house

Uncertainty about Design Flow - 90 percent probable ± range of flow. Depends on the available knowledge of the area

Factor Fraction of Possible kW.h - firmness of creek based on MAF. A computer program (run on the Boeing computer in Seattle) was developed to use available stream flow records at about 75 selected sites to construct a map of firmness for British Columbia (a smaller, simplified firmness map was included in the Phase 1 study report)

Uncertainty about Factor Fraction	-	90 percent probable ± range of firmness. Depends on the available knowledge of the area
Nearest Distribution Line Rating (in kV)		
Distance to Distribution Line (in km)	-	distance measured (on topographic map) to nearest distribution line. If the nearest distribution line had a high kV rating and the site was small, then the next nearest low kV line was chosen. The suitability of the transmission line to accept the power has not been checked at this level of study.
Available Storage	-	(as percentage of basin)

The following variables were then determined by the computer program.

1. Gross head (m) = Intake Elevation - Power house elevation

   Remarks: - self explanatory

2. Average Slope of Penstock = Gross Head/Length of Penstock

   Remarks: - self explanatory

3. Penstock Length - SQRT ((Gross Head)^2 + (Horizontal Length of Penstock)^2)

   Remarks: - actual length varied little from measured horizontal length except for penstocks having a steep gradient.

4. Calculated Penstock Diameter = (0.43182) x ((Design Flow)^2 x (Penstock Length)/(Gross Head))$^{(3/16)}$

   Remarks: - a penstock diameter was selected to yield a net head equal to 90 percent of the gross head (fairly standard practice for preliminary design). Mannings equation was used with n = 0.0105 for steel.

5. Nearest Available Penstock Diameter - a lookup table was used

   Remarks: - closest steel penstock diameter available from one local supplier was chosen.

6. Net Head = Gross Head - (0.001135) x (Design Flow)^2 / (Available Diameter)$^{(16/3)}$ x (Penstock Length)

   Remarks: - this is the actual net head obtained when the nearest available penstock diameter was used (based on Mannings equation with n = 0.0105).

7. Thickness Factor - a lookup table was used

Remarks: - this factor is applied to the maximum thickness required by the penstock to determine an average thickness. A different thickness factor is used for each increment of 50 metres of head. This assumes that the thickness of the penstock will increase from the intake to the power house.

8. Minimum Thickness - a lookup table was used

Remarks: - this is the suppliers minimum thickness required for safe handling.

9. Average Thickness Calculated = $6.191 \times (10)^{(-5)} \times$ (Gross head) $\times$ (Available Diameter) $\times$ (Thickness Factor)

Remarks: - the hoop stress formula was used with a safety factor of 1.3 to account for water hammer effects.

10. Volume of Steel Penstock =($(\text{Penstock Thickness})^2$ + (Penstock Thickness) x (Available Diameter)) x PI x (Penstock Length)

Remarks: - penstock thickness used is the greater of the minimum thickness available and the average thickness calculated.

11. Additional Costs due to Slope = 1 + (Slope of Penstock - .15) for slope greater than or equal to 15%

Remarks: - adds 1% to cost of penstock for every additional 1% of slope in excess of 15%.

12. Plant Capacity = (Design Flow) x (Net Head) x 8

Remarks: - this assumes a plant efficiency of 81% and a specific gravity of water equal to 9810 N/m^3

13. Economy of Scale Factor = $5 \times (\text{Plant Capacity})^{(-0.16)}$

Remarks: - this is an empirical equation developed to account for the economies of scale seen in hydro projects.

14. Cost of Penstock = (Volume of Penstock in m^3) x (Slope Factor) x (7850 kg/m^3 (density of steel)) x (Site Factor) x (\$4/kg) x (1.62 x (Diameter)$^{(0.0845)}$)

Remarks: the last term is an empirical economy of scale factor for penstocks. The previous economy of scale factor is not used here as diameter is more important than plant capacity which relies on flow (related to diameter) and head.

15. Intake Cost = ((Design Flow) x 34,293 + 17,342)
x (Economy of Scale Factor) x (Site Factor)

Remarks: - Based on empirical equation from previous experience

16. Generating Equipment Cost = 16,000 x (Plant Capacity)$^{(0.7)}$
x (Net Head)$^{(-0.35)}$) for projects less than 5 MW
= 1.43 x (10)^6 x ((Plant Capacity / 1000))$^{(0.92)}$
x ((Net Head)$^{(-0.32)}$ x (Plant Capacity / 1000)$^{(0.058)}$)))

Remarks: - equation is based on an article entitled "Quick Estimating Techniques for Small Hydro Potential" Water Power and Dam Construction, September 1979. Costs were brought forward to 1982 Canadian Dollars.

17. Turbine Speed and Type Code - a lookup table was used

Remarks: - the program selected a turbine type and specific speed based on gross head and plant capacity. The turbine speed was generally chosen to be as fast as technically possible to reduce turbine and generator size which would reduce the size and cost of the power house.

18. Turbine Speed = Integer of (Turbine Speed and Type Code) x 10

Remarks: See #17 above.

19. Turbine Type = 0.75 for Francis turbine
= 0.45 for Pelton

20. Power House Length = (SQRT (Net Head) x (126)/(Turbine Speed) + 3.7)
for Pelton

= (SQRT (Net Head) x 385/(Turbine Speed) + 3.7)
for Francis

Remarks: - this dimension is dependent on the turbine principal dimension which is the turbine throat. An additional 3.7 metres is provided for clearance requirements.

21. Powerhouse Width = (SQRT (Net Head) x 73.6/(Turbine Speed) + 2.1 + 4
x (Available Penstock Diameter))
for Pelton turbine

= (SQRT (Net Head) x 228/(Turbine Speed) + 2.1 + 4
x (Available Penstock Diameter))
for Francis turbine

Remarks: - this dimension is dependent on the turbine throat and the penstock diameter. An additional 2.1 metres is provided for clearance requirements.

22. Power House Cost = (Powerhouse Width) x (Power House Length) x (Economy of Scale Factor) x (Site Factor) x ($1600/m^2)

Remarks: - empirical, based on previous experience.

23. Access Road Cost = (Access Road Length) x (13000 + 9592 x ln (Plant Capacity))

Remarks: - as the hydro plant gets larger, the access road must become better, so cost/km goes up. A small plant may have an access road that costs $45,000/km where a large plant may have an access road that costs $110,000/km.

24. Contingencies Cost - 30% added to cost of project

Remarks: - at this level of study, a factor of 30% was required to account for grid tie-in (5%) and any unforeseen problems.

25. Engineering Cost = (0.12) x (Economy of Scale Factor) x (Capital Cost including Contingencies)

Remarks: - accounts for varying amount of engineering required for projects of different size. A small project might require the engineering cost to be 30% of the capital cost whereas a large project might require an engineering cost of only 8%.

26. Transmission Line Cost - not included in the Phase 1 study report

Remarks: - this is included in the Phase 2 study as part of the total capital cost. The cost/km of transmission line depends on the distance and the amount of power to be transmitted. Transmission line costs vary from $50,000/km to $80,000/km.

27. Capital Cost (without transmission)

Remarks: - Computed based on the above formulas.

28. Capital Cost (with transmission)

Remarks: - computed based on the above formulas

29. Total kW.h/year = (Firmness Factor) x (Plant Capacity) x (8760 hrs/yr)

Remarks - this study also includes a factor of 0.85 to account for transmission line losses (5%) and down time losses (10%).

APPENDIX 5

APPENDIX 5

BC HYDRO SYSTEM AND POWER DEMAND FORECAST

The method used to derive the MEMPR forecast for the BC Hydro System is summarized as follows:

- The provincial gross electricity requirements are presented in Table 9.1, page 9-2 of the latest forecast (Reference 6) at five year intervals from 1980 to 1995.
- From the gross requirements was subtracted the supply of electricity from non-BC Hydro sources which was inferred from Table 8.3, page 8-9. In 1985 and thereafter, a total of 41.4 PJ (11,500 GW.h) was subtracted from gross requirements on the BC Hydro system only. Since the supply of non-BC Hydro electricity remains constant after 1985, then all of the growth in requirements is on the BC Hydro system.
- The MEMPR forecast, given in five year intervals, was converted to an annual forecast by assuming a constant growth rate over the intervening years.
- The electricity supply forecast was taken from Table 8.3, page 8-9, assuming average water conditions and with an in-service date of 1984 for the Revelstoke Project. Throughout, petajoules were assumed equivalent to 277.78 GW.h.
- The resulting forecast is presented in the following table, Column 1. If we take the small hydro potential to be 1,377 GW.h, then this is sufficient to meet two years plus of load growth.

It must be emphasized that the purpose of the discussion in the report was to illustrate the flexibility of small hydro power development that was not captured in other analyses (e.g. with regard to planning system additions and in matching load growth). These features apply no matter what forecast is assumed. However, this flexibility is clearly more significant during low growth periods.

B. C. HYDRO

COMPARISON OF ACTUAL ENERGY REQUIREMENTS WITH PROBABLE FORECAST OF TOTAL GROSS REQUIREMENTS (%)**

	YEARS AFTER FORECAST										
	1	2	3	4	5	6	7	8	9	10	11
1963 (probable)	0.1	-3.5	-10.8	-17.3	-20.5	-24.8	-25.7	-28.1	-31.4	-35.6	-38.0
1964 (probable)	-1.6	-4.1	-7.6	-9.0	-14.4	-15.7	-18.1	-22.8	-27.6	-31.3	-30.3
1965 (probable)	-1.8	-4.4	-1.0	-3.6	-4.5	-6.6	-11.6	-18.5	-22.7	-22.4	-19.5
1966 (probable)	-0.1	2.7	2.0	-0.5	0.1	-5.6	N/A	N/A	N/A	N/A	N/A
1967 (probable)	0.4	0.2	1.3	-0.2	-3.8	-9.5	N/A	N/A	N/A	N/A	N/A
1968 (probable)	-1.6	-1.9	-0.4	-2.6	-8.4	-11.7	N/A	N/A	N/A	N/A	N/A
1969 (probable)	0.1	1.9	-0.9	-4.4	-9.0	-7.4	-2.8	-7.0	-7.1	-7.4	-3.0
1970 (single)	-0.8	4.2	1.8	1.3	5.6	12.1*	9.6*	11.4*	12.9*	19.6*	25.5*
1971 (single)	0.6	0.9	1.2	6.7	14.7	12.5*	15.0*	16.5*	23.8*	29.5*	35.7*
1972 (single)	-1.8	-1.4	2.8	12.1	11.1	14.4*	16.8*	23.9*	29.3*	35.6*	
1973 (single)	0.5	4.8	14.0	12.9	17.7	20.5*	29.5*	36.7*	43.5*		
1974 (single)	-0.5	5.3	5.3	12.7	16.7	25.2*	31.2*	38.9*			
1975 (single)	-0.6	2.2	5.0	9.9	18.6	26.1*	32.6*				
1976 (probable)	0.7	3.4	4.7	11.3	18.5	24.8					
1977 (probable)	0.4	-0.8	2.3	5.1	7.3						
1978 (probable)	-1.4	2.0	2.8	5.3							
1979 (probable)	1.2	3.0	7.6								
1980 (probable)	0.9	5.6									
1981 (probable)	-0.1										

* High forecast.

** Difference between forecast made 1 to 11 years prior to year indicated divided by actual. A negative sign indicates forecast is too low.

10 September 1982

ELECTRICITY REQUIREMENTS BALANCE
(B.C. HYDRO SYSTEM ONLY)

	1	2	3	4	5	6	7
	Gross Requirements[1] (EMPR)	Supply[2]	Supply Deficit	Gross Requirements[3] (BCHPA)	Supply Deficit	Small Hydro[4] (EMPR)	Small Hydro (BCHPA)
1980	30,306			30,996			
1985	39,639	47,778	-	37,875	-		
1986	40,988[5]		-	40,100	-		
1987	42,383[5]		-	41,920	-		
1988	43,826[5]		-	43,440	-		
1989	45,318[5]		-	45,120	-		
1990	46,861		-	47,060	-		
1991	47,510[5]		-	49,330	1,552		1,371
1992	48,167[5]		389	50,900	3,122	389	
1993	48,834[5]		1,056	52,600	4,822	1,056	
1994	49,509[5]		1,731			1,377	
1995	50,195		2,417				

1. MEMPR, April 1981, Table 9.1 Net of Non-BCHPA Supplies in Table 8.3
2. Includes Revelstoke capacity/firm energy supply
3. B.C. Hydro & Power Authority; Projection of Gross Load Requirements, September, 1982, pg. 125, table 7-3.
4. From draft Economic and Financial Assessment, assumes small hydro potential of 11,377 GWh/yr.
5. Values estimated by interpolation

Number/
Numéro

2

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Note: As some of the maps have been reduced for this reproduction, map scales are not necessarily accurate.

First printing, February 1984

PROVINCE OF BRITISH COLUMBIA

MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES

SMALL HYDRO POWER RESOURCE
IN THE PROVINCIAL SYSTEM

TECHNOLOGY AND RESOURCE ASSESSMENT

SEL 5242
JULY 1983

SIGMA ENGINEERING LTD

FOREWORD

The study of the small hydro power resource in British Columbia resulted from a growing interest in the subject, both from the viewpoint of the private investor and of the Provincial Government who are responsible for managing the resource. Its purpose is to serve as both a development manual and a catalogue of the entire resource, as it pertains to the integrated or remote grid systems of the provincial utilities.

It should be noted that the baseline date for the study is the spring of 1982, when most of the research was done. Since then until the final completion of the report in late 1983, a number of report revisions have occurred, but the baseline data have remained the same.

During the past 1½ years there have been changes in power rates, public utility policies, government policy and interest rates. These factors play a significant role in determining the feasibility of any power development and they must be verified during the course of a small hydro power study.

The scope of this report can be summarized as follows:

- to the provincial government, it provides both a magnitude and distribution of the resource with some ideas for shaping public policy toward future small hydro power development;
- to the investor, it provides guidelines for developing small hydro power sites from a technical and regulatory viewpoint;
- to the individual with a requirement for his own power supply, it provides step by step guidelines to establish preliminary designs and costs of a small hydro power system.

An investigation of the site conditions, which may comprise the largest variable in small hydro power development, was beyond the scope of this report. It cannot be overemphasized that any prospective site must be investigated on the ground at an early stage. With this in mind this report can provide a starting point for the further development of the resource in an organized and economical manner.

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1. INTRODUCTION

1.1 BACKGROUND

The first small hydro power schemes in British Columbia were constructed in the late 1800s. The number of operating plants increased for a while, but then began to decline as more economical sources of energy became available. The alternative sources were the expanding provincial grid supplying inexpensive power from major hydro power developments, and diesel generators serving settlements too remote to be connected into the grid.

In recent years however, the prospect for the development of small hydro power sites has become much more promising. In the case of systems now supplied by diesel generation, this is due to the large increase in the cost of diesel fuel since the energy crisis of 1974. In the case of the provincial grid, the cost of energy provided by the new large hydro power sites is beginning to approach or exceed the cost of energy from prime, small hydro sites.

There are a number of reasons for promoting small hydro power as a renewable energy resource. Individual developments are small and therefore benefits from construction are likely to be widely dispersed, and the disruptions associated with very large projects are avoided. Although small hydro power is capital intensive, most of the expenditure is for design, construction, materials, and equipment which are readily available in Canada. Operating costs of a small hydro plant are low, so the energy produced is relatively inflation proof. Finally, British Columbia is especially fortunate with its steep topography to develop high head (high water pressure) small hydro power projects.

Not only would small hydro power projects serve as useful energy sources, but they also provide an opportunity to develop the technology and make British Columbia a world leader in this small but significant field, leading to the possibility of exporting equipment and engineering services.

In order to assess the small hydro power resource in the provincial system, two complementary studies were commissioned by the Ministry of Energy, Mines and Petroleum Resources, and completed in July 1983.

In this primary study the status of the technology of small hydro power was first reviewed. Then an inventory was developed covering the hydro power sites in British Columbia with an installed capacity of less than 20 MW, which are in suitable locations for interconnection with the B C Hydro and the West Kootenay Power and Light systems, or with local distribution lines. However the numerous logging camps, fishing camps, mines, resorts, Indian villages and private residences which generate their own power were not catalogued during this study. These remote sites, some of which are already served by a small hydro power plant, were covered in a previous report, **Micro Hydro, (Crippen, 1980).**

Preliminary estimates were made of the available installed capacity and the relative cost of energy at individual sites, but site investigations were not made.

The report also deals with the technical and legal aspects of connecting a small hydro power scheme to a larger electrical system.

The companion volume to this report builds on the cost data developed here in order to determine the economic feasibility and the financial viability of the resource, and is entitled, **Small Hydro Power Resource in the Provincial System, Economic and Financial Assessment.**

1.2 TERMS OF REFERENCE

In February 1982, SIGMA Engineering Ltd were authorized by the Ministry of Energy, Mines and Petroleum Resources to undertake a study of the small hydro power potential of British Columbia and a review of the technology.

The detailed scope of work is as follows:

PHASE 1 - TECHNOLOGY UPDATE

Small Hydro Power Equipment

- provide typical equipment specifications on types of systems likely to be used in British Columbia. Components will include civil works, penstocks, turbines, generators, controls, protection equipment and transmission equipment;

- provide approximate cost information on the above works to assist in evaluating project proposals;

- provide examples of equipment configurations, and the benefits of certain arrangements.

Interconnection Policy

- collect information from utilities to assess the magnitude of legal and technical requirements which will be faced by small hydro power installations connected to the grid.

PHASE 2 - RESOURCE ASSESSMENT

Hydrology

- provide a method of design flow estimation based on rainfall statistics, streamflow measurement and mapping.

Power Potential

- estimate the potential for the connection of small hydro power schemes to the provincial electric grid, using actual basins as examples;

- estimate the potential for the connection of small hydro power schemes to isolated systems, particularly B C Hydro diesel generation systems.

2. TECHNOLOGY ASSESSMENT

2.1 BACKGROUND

The use of falling water as an energy source dates back to the earliest waterwheels, but the modern era in hydro power development began with the invention of water turbines in the 19th century. These early turbines were used in mills for driving machinery, but this use was limited by the difficulty in transmitting and distributing power mechanically. With the further development of electrical technology, it became possible to generate and transmit power for both commercial and domestic purposes. As the use of electricity became widespread, electrical transmission grids developed, and larger and larger electrical generating stations were constructed to exploit economies of scale. In the case of hydro power systems, the development of high voltage transmission technology allowed large remote sites to be developed and tied into power grids.

Since the invention of the turbine, water power technology has been developing continuously, but as with other technologies the main conceptual breakthroughs came in the early stages with later refinements in design, materials and manufacturing techniques. Because of the trend towards larger schemes, most of the development work became concentrated on large turbine/generator units, and since the 1940s there have been relatively few small units installed, and indeed many early small power plants were allowed to fall into disuse as it became more economical to buy power from the grid than to maintain the older, smaller systems in operation. Thus small hydro power technology stagnated with few new developments and many of the manufacturers went out of business. At the same time some of the side effects of large projects began to be apparent, and pressure to preserve the environment led to increasingly complex licensing requirements. The same procedures tended to be applied to small and medium sized projects which further reduced the incentive to develop small and medium sized hydro power plants.

The situation began to change in 1974 when oil prices increased suddenly thus increasing the cost of electrical energy generated in oil fired thermal power plants. This led to an immediate search for alternatives, including a second look at the neglected small hydro power resource. Although an attractive alternative, with many potential advantages, small hydro power was still entangled in the same regulatory maze as large hydro power and this offset the advantages.

A significant breakthrough for small hydro power development in the United States came when the Federal Energy Regulatory Commission (FERC) adopted the Public Utility Regulatory Policies Act of 1978 (PURPA). This regulation defined small hydro power systems (less than 80 MW), established regulations which would permit their operation and obligated electric distribution utilities to buy the generated energy and capacity at rates equivalent to their avoided cost (i.e. the cost of the more expensive energy the utility would normally have to purchase to supplement its less expensive base load power supplies). The Department of Energy funded comprehensive studies on small hydro power assessment and offered loans and grants to help establish small hydro power facilities. Direct benefits of the legislation have been felt in British Columbia, where several local turbine manufacturers have received orders for turbines for the United States. The indirect benefits are that legal and technical precedents have been established and there is now a competitive market for turbine equipment.

The growth of electrical consumption and distribution in British Columbia has followed a similar pattern to that outlined above. Since BC Hydro system costs are virtually independent of thermal generation and only a small portion of the system is powered by diesel, most of the consumers of electrical energy in British Columbia have been insulated from the dramatic price increases faced by some others. In fact, the average price of electricity in real terms dipped between 1964 and 1974, and from then until 1980 it closely followed the trend of the consumer price index. Despite the growth in the transmission system, there are still a large number of isolated communities whose distance and intervening topography separate them from the provincial electric grid. System operators in these isolated areas, including BC Hydro and private producers, face the full impact of price increases in fuel supplies, and they stand to gain the most from small hydro power systems. Under the right circumstances small hydro power systems can also be economic in areas already served by the electric grid. However, procedures for licensing and buying the power from small hydro power developments have not yet been set up and streamlined in British Columbia.

The result of the favourable economic climate for small hydro power has been a large increase in business for established suppliers of equipment and the formation of many new firms to market and sell the products. Until recently the concentration has been on larger projects, leaving many small turbine designs based on old technology, with few changes over the years. On the other hand, the electrics have improved considerably with the development of compact, more efficient generators, brushless exciters, electronic voltage regulators and more recently the adaptation of microprocessors to the control and data logging of small hydro power plants. These applications allow improved and less expensive speed regulation, control and monitoring systems to be used with small systems. These new innovations are discussed along with the existing technology in the following sections.

2.2 HYDRO POWER SYSTEM DESCRIPTION

A hydro power system, regardless of size, requires several components to convert the potential energy of the water into electrical energy and safely transmit it to the power user. Water must be admitted through an intake (with or without a dam) and carried in a pipe (a penstock) to the powerhouse. The pressure of the flowing water is converted to mechanical energy by the turbine, which drives the generator. The generator converts the mechanical energy of rotation into electrical energy at a relatively low voltage. The energy is then fed through a transformer to increase the voltage to that of the transmission line which carries the energy to the customer, where transformers are again used to reduce the voltage to an acceptable level for consumer use.

An automatic turbine governor is required to control generator speed so that a constant output frequency (usually 60 Hz) is maintained. Typically, there are numerous fault detectors which are set to shut down the turbine if problems with the equipment or unstable conditions develop. Protective devices are also provided to prevent harmful electrical conditions in the grid line (if it is so connected) from damaging the generator. In general the complexity of the protection system increases with the output of the plant and the transmission voltage.

A diagram of a typical system is shown in Appendix 3, Figure 3.1. The components at each site will be different, but the overall configuration would be similar.

2.3 TURBINES

The first turbines were water wheels, which depended on the weight of falling water in buckets to turn the wheel and drive machinery. These systems have been used for centuries and were used in British Columbia in the early days of the mining industry.

It was not until the mid 1800s that the first pressure turbines were developed. These too were water wheels, but the driving force was the action of a pressurized jet of water. A number of companies became involved in the production of these systems as any machine shop with a forge could fabricate the product. A few of these companies which started out with a well manufactured product have survived the many ups and downs of the industry for over 100 years.

Once the use of electricity became widespread, the need for hydraulic turbines increased. Accordingly the developments in the hydraulic machinery field were rapid and more powerful machines were evolved. Applications for the water wheel or Pelton wheel became limited to high head situations where large power outputs could be provided. Medium head reaction turbines known as Francis turbines were developed, as well as low head propeller turbines. The low head propeller turbine with variable pitch blades for higher efficiency at partial flows became known as the Kaplan turbine.

The most recent developments in turbines include the Crossflow turbine which was invented in the early 1900s and the Turgo Impulse wheel invented in 1920.

The Crossflow turbine uses a vaned wheel on a horizontal shaft. It is used in a variety of applications, sometimes replacing an impulse (Pelton) machine and sometimes a reaction (Francis) type. Its advantages are that it produces power at a reasonable efficiency under conditions of varying head and flow. The Turgo Impulse wheel was designed to suit applications in between the optimum ranges of the impulse and reaction turbines. It is classed as an impulse turbine, but because of its shape, it has a higher power output for the same runner diameter and within its range it is usually more economical than the impulse or reaction turbines with similar outputs. The range of peak efficiences for hydraulic turbines is from about 80 to 90 percent or higher. The characteristics of the various turbines commonly used for small hydro power projects in British Columbia are shown in Table 2.1.

Since the early part of the century the basic turbine designs have changed little and most of the improvements have been in manufacturing techniques and materials. The original cast iron runners have been replaced with bronze and stainless steel runners, which are more corrosion and cavitation resistant.

Cavitation can occur when the water velocity is high and the pressure is low, such as occurs at the discharge end of a reaction turbine. Because of the low pressure the water literally boils and produces vapour filled cavities which can then collapse suddenly when carried to a region of locally higher pressure. If the collapse occurs on the equipment surface severe erosion and damage can result. The cavitation problem continues to affect even newer turbines, since there has been a tendency to produce smaller, faster machines which are less expensive. The faster a machine rotates, the more likely it is to suffer cavitation damage particularly to the turbine runner. Most manufacturers are careful to specify the head, elevation above sea level, water temperature and elevation above or below tailwater for which their machine is designed to operate without cavitation. It is important to minimize the potential for cavitation by carefully following the manufacturer's recommendations. Faster turbine speeds also increase the wear on bearings, and additional cooling and lubrication systems may be required.

A persistent problem with turbine manufacture is that virtually every machine is unique. There are infinite combinations of flow and head, hence an almost infinite number of designs. Each time an order is received, the turbine must be designed to suit the site parameters and, in the case of large turbines, hydraulic models are usually tested before actual fabrication begins. Manufacturers that have been in business for a long time will usually save their old patterns, but even these may require modification each time they are reproduced. The result is that delivery of most small turbines takes at least one year. Very small turbines (for household use) can sometimes be purchased off the shelf while delivery of the larger turbines may take even longer than one year.

An idea that is finding increasing acceptance for small hydro power projects, particularly the very small (less than 50 kW) range is the use of pumps as turbines. By reversing the flow through a pump it can be made to run at a similar efficiency as its pump efficiency and at a higher head and flow, meaning higher output. There are numerous manufacturers of pumps, so selection can be wide, prices competitive and delivery times short. The selection process should include obtaining design curves from manufacturers (assuming that they have tested their pumps as turbines), checking the durability of the pump as a turbine, and coordinating the connection of the pump to the generator.

The improved market for hydraulic turbines, especially in the United States in the low head range, has resulted in several manufacturers producing standardized packaged units. This has been the biggest advance in small hydro turbine technology in recent years. Unfortunately it has largely been confined to low head units, while in British Columbia the most common requirement is for medium and high head units. Standardization has helped shorten the time from the conceptual to the commissioning stage and reduce the cost. The greatest benefit has occurred to the small hydro power sites where existing civil works are in place and upgrading is being considered. The main types of packaged units, all of which are used on low heads, are summarized in Table 2.2.

TABLE 2.1
TURBINE CHARACTERISTICS

Sheet 1 of 2

Type	Application and Advantages	Disadvantages
Pelton Head: to 1000 m Output: to 20,000 kW	- High heads, low specific speed. - Good efficiency over a wide range of flows. - High RPM reduces generator cost. - Few moving parts. - Water from the turbine discharges freely and has only to be channeled away. This simplifies the civil works.	- Some loss in head because turbine discharge must be above maximum tailwater level.
Francis Head: to 300 m Output: to 500,000 kW	- Medium heads - High efficiency at rated output - Moderate Specific Speed - High capacity	- Efficiency falls off at part load. - Tailwater level must be controlled to avoid cavitation - Many moving parts
Crossflow Head: to 200 m Output: to 2500 kW	- Medium to high heads - Efficiency nearly constant over wide range of flows - Low specific speed - Few moving parts - Water from turbine discharges freely so no need to control tailwater level	- Lower overall efficiency - Must use fine debris screens - Can be noisy
Turgo Head: to 250 m Output: to 4500 kW	- Low to moderate Specific Speed - Covers a range where Francis and Pelton turbines are at the limit of their application - Few moving parts - Water discharges freely so no need to control tailwater level	- Some loss in head because turbine discharge must be above tailwater

TABLE 2.1
TURBINE CHARACTERISTICS

Sheet 2 of 2

Type	Application and Advantages	Disadvantages
Propeller Head: to 30 m Output: to 50,000 kW	- High Specific Speed - Low Head	- Physically large - Efficiency is good only near rated output - Sensitive to tailwater levels
Kaplan Head: to 30 m Output: to 50,000 kW	- High Specific Speed - Low Head - High efficiency over a wide range	- Complicated mechanically - Physically large - Sensitive to tailwater levels
Reversible Pump Head: Varies Output: Varies	- Suited to very small installations - Can be purchased "off the shelf" - Much less expensive than a turbine, for the same output - Good selection, many manufacturers - Suited to steady load	- Slightly lower efficiency - Design coordination required to match pump to generator - Is really only suited to continuous operation at full load as efficiency falls off rapidly at part load.

Definitions

Head: The effective height of water above the turbine.
Gross head is the intake level minus tailwater level.
Net head is gross head minus energy losses in the penstock.

Specific Speed: A means of classifying turbines as to type.
Turbines of identical geometric shape but of different size will have the same specific speed.

$$\text{Specific Speed (English units)} = \frac{\text{Operating Speed RPM} \times \text{Horsepower}^{\frac{1}{2}}}{\text{Head}^{1.25}}$$

The pricing of turbine units is not straightforward due to the large number of variables in turbine design, and at the planning stage reliance is placed on experience curves based on what delivered units have cost in the past. The usual inflation factors can then be applied to estimate a current price. Generally arriving at a final price is much more complicated. The turbine business is international in scope, so exchange rates, import duties, delivery time, interest rates, language and shipping problems must all be considered in respect of purchases outside Canada. Federal sales tax will also be applied at the port of entry, but this can be refunded if the proper procedures are followed. Even a portion of the duty can be refunded if it can be proven that no Canadian firm could fill the order. The bidding climate at the time of ordering can also affect the cost of the turbine. With some manufacturers overworked, certain enquiries may not receive favourable consideration unless the job fits the particular production schedule of the company. It is important to direct the enquiry for information and the tender request to suppliers that are both capable and willing to perform the work. In Appendix 3, Page (i) some of the manufacturers of small hydro turbines are listed, together with some typical specifications, while cost curves are presented in Appendix 2, Figure 2.3.

TABLE 2.2

PACKAGE TURBINE SETS

Type	Application and Advantages	Disadvantages
Bulb	- Low head, direct coupled generator to propeller turbine enclosed in waterproof chamber suspended in water passages - Riser pipes connect to powerhouse floor level for servicing	- Possible leakage problems - Complicated civil works for water passages
Tubo (Allis Chalmers)	- Horizontal shaft propeller turbine with curved water passages made of steel - Generator and controls easily accessible in powerhouse	- Long shaft - Bearing design and sealing are critical
Straflow or Rim Generator	- The generator stator is embedded in the concrete water passage, with the rotor attached to the turbine blades - Compact	- Potential sealing problems with electrical components - Complicated design
Mini Hydel (Barber Turbines)	- Prefabricated factory built unit consisting of a Francis or propeller turbine, generator, gear box, governor and controls built for low heads and power outputs to 1000 kW - Provides for rapid installation of the principal components, often with a minimum of related civil works.	

2.4 GENERATORS

The technology of generators is well established and there are many manufacturers in the business. However, there tends to be a size distinction, with one group of manufacturers supplying the lower speed range, physically large machines, while another group specializes in the smaller high speed machines. The large generators are generally custom built, one of a kind designs. The more common high speed generators are standardized to some extent for application to the diesel generator and small hydro market. They generally operate at 1200 - 900 RPM and are geared to suit turbine speed. Large hydro power projects and those operating in isolation invariably use synchronous generators while small hydro plants operating in parallel with the utility or an existing synchronous generator may use an induction or asynchronous generator. Their merits are discussed below and compared in Table 2.3.

Synchronous Generators

Synchronous generators are available in a wide range of sizes and can be used either in parallel with an existing system or in a remote installation. The synchronous machine has its own DC excitation system and voltage regulator, which provides for control of the output voltage over a range of loads.

Within its rating the synchronous generator can operate at a leading power factor and provide for the demands of lagging power factor loads such as induction motors and fluorescent lights. These loads require a higher kV.A (kilovolt ampere) capability even though the rated power (kilowatts) may be the same as a resistive load with a power factor of unity.

In the case of an isolated system the turbine governor is required to control generator speed so that a relatively constant output frequency, usually 60 Hz, is maintained at all loads within the capability of the turbine and generator. In a parallel system it is necessary to control and match the generator no-load frequency, voltage and phasing so that the generator can be synchronized with the system. The degree of frequency and voltage control (regulation) required is a function of the type of electrical loads being served. Lighting loads require reasonable voltage control while motor loads require relatively close control of

TABLE 2.3

GENERATORS

Type	Application and Advantages	Disadvantages
Synchronous	- Isolated systems	- Multiple units must all be synchronized
	- Large systems	
Asynchronous or Induction	- Less expensive than synchronous generator in smaller sizes	- Must be feeding into a much larger power system with synchronous machines
	- Ideally suited to small systems tied to a power grid	- Requires separate overspeed control
	- Does not require a governor as speed is controlled by the main grid system	- Size is limited
	- Rugged construction	- Lagging power factor may need to be compensated

both frequency and voltage to enable the motors to perform at design speed and load.

Induction Generators

Induction or "asynchronous" generators obtain their excitation from the power system they are connected to and as such can only be used in parallel with synchronous machines. They are similar in construction to an induction motor and more rugged than a synchronous machine and generally less expensive. The governor system may be simplified to a load control system since the generator will match its speed with that of the controlling system frequency.

There are a few disadvantages to the induction generator. The first, as previously mentioned, is that it cannot operate in an isolated system but must be part of a larger system which provides stability, and voltage and frequency control. The second is due to the fact that generation is brought about by the turbine attempting to speed up the induction generator above system synchronous speed and thereby feeding power into the system. In this situation, when system load is suddenly lost, the turbine and generator immediately begin to speed up and a sensitive and reliable overspeed trip and a stored energy type shutdown device is required to protect the rotating machines from damage. Larger induction generators may draw excessive inrush current and cause considerable voltage drop when starting as a motor. In addition, power is fed into the network at a lagging power factor which requires that var support comes from the system, something which may not be acceptable to the utility without further consideration of power factor correction. Examples of generator suppliers and related information are given in Appendix 3.

2.5 GOVERNORS

The governor is the most complicated and sensitive device in the hydro turbine system. It is designed to sense speed variations, which are indicative of load changes, and adjust the flow of water to the turbine to maintain a 60 Hz frequency.

Originally, many turbine manufacturers made their own governors. However, this field is now dominated by the Woodward Governor Company of Rockford, Illinois. A few foreign turbine manufacturers make their own governors and more recently there have been electronic governors developed for small systems.

The most common type of governor is the gateshaft governor with accumulator. It operates with an electric motor drive operating at the same frequency as the generator. When the generator frequency changes due to a load change, the speed of the drive motor changes and mechanical linkages are activated which change the flow of pressurized oil in the servo system. The servomotor (a hydraulic piston) acts to open or close the turbine gates and hence correct the speed of the turbine. This form of system has been available for many years, is very reliable, and comes in different sizes for different turbine loads. A disadvantage is that it is available only in larger sizes so that very small capacity turbines are faced with a relatively high fixed cost.

The newer electronic load dumping governors are designed to economically govern the smallest hydro plants. The system features a load bank of resistors controlled by an electronic sensor. The sensors control the load into the resistors such that the total load on the generator is constant. When the power requirements of the load decrease, the power to the resistor banks increases by the same amount. This system is only limited by the size of the resistor banks and the cost of dissipating a potentially large concentration of heat. There is an advantage in that the constant load reduces the need for surge tanks or pressure relief facilities. The turbine will operate at full flow until there is a shut down, at which time the load is picked up by the resistor banks and the turbine will be shut down slowly. The governor can also be tied in to intake water level sensors to regulate power outputs when flows are low, or conserve water if required.

The various types of governors are described in Table 2-4 and specifications are covered in Figure 3.3.

TABLE 2.4

GOVERNORS

Type	Application and Advantages	Disadvantages
Gateshaft	- Virtually all sizes of small hydro turbines	- The cost of the minimum size can be a high proportion of the cost of a small installation
Electronic	- Suited to small installations - Inexpensive - The size of the governor varies with the size of the turbine output - Makes possible a better load factor and fuel substitution at remote sites	- Excess energy turned into heat must be dissipated - Requires full flow until the unit is shut down.

2.6 PROTECTIVE DEVICES

Hydro power systems have always used protective devices to some extent, but advances in electronics and customer requirements for more sensitive operation have tended to increase the level of protection provided. There are two categories of protection systems that may be required, hydro-mechanical protection for the plant and electrical protection for the power system.

Hydro-mechanical Protection

Protection of the physical operating features of the plant is important to prevent the turbine from being damaged if a harmful condition arises. The basic system involves a monitoring probe, which measures a critical parameter, linked to a relay which in turn is linked to a warning or shut down system. The parameters monitored can include bearing temperature, turbine speed, vibration, gate position, water temperature, head pond levels, trash rack conditions, oil flow, accumulator pressure or any other plant system features whose malfunction can lead to trouble.

The penstock can also be protected from water hamnmer conditions arising from rapid turbine shutdown through the use of jet deflectors on the turbine, surge towers, pressure relief valves or bypass valves.

Electrical Protection

The subject of electrical protection is one of the more difficult to define in the small hydro power system, as well as involving some of the most complicated details. Details usually are entirely site specific. In an interconnected system, there must be protection provided for the generator against conditions arising in the utility, the generator and powerplant Itself. The utility must be protected against conditions arising in the powerplant.

The utility must be protected to ensure that its customers are not subjected to power fluctuations from any of the generators tied into the system. The types of conditions protected against vary with the output of the generator, the classification of the receiving transmission line, and the particular utility requirements.

The generator must be protected against conditions arising from the utility. For example, lightning or wind can cause transmission line problems which must be prevented from affecting the small hydro generator. Typically a breaker would be provided to put the small hydro generator off line if a problem arose in the larger utility system.

The powerhouse itself can also be subject to numerous problems in addition to the mechanical aspects already mentioned. Details of the protection systems would depend on the type of generator, governor, transformers, breakers and relays already in use.

The final authority on the types of protective devices used will be the utility which is allowing the customer owned generator to connect. Only the utility can determine the impact of the proposed generating facility on its system and it must take reasonable precautions to ensure that its interests are protected, without being unreasonable to the prospective developer of a small hydro power scheme. Basic details must be outlined in the utility's interconnection policy, but these can only serve as a rough guide, which cannot cover all of the possibilities. Thus the utility will play an important role in the process, by outlining the basic requirements and reviewing the proposals.

In a typical project connected to a low voltage distribution line, the systems below might be incorporated. It is important that all the systems be designed together to ensure that they are coordinated with each other:

To protect the generator from the utility:

- lightning arrestors, fuses, load breaks

To protect the utility from the generator:

- under and over voltage protection
- under and over frequency protection

To protect the generator and turbine mechanically

- overspeed control
- bearing temperature control
- vibration control

An example of a protection system used on a small hydro power project is shown in Appendix 3, Figure 3.4.

2.7 PENSTOCKS

Hydro power systems originally had few choices for penstock construction, with the primary materials being cast iron, rivetted steel and wood stave pipes.

In modern small hydro power systems there are numerous choices for the penstock material, and no pipe type is clearly the best choice for every situation. Availability, pressure rating, friction loss, site conditions, ease of installation and price must all be considered before a final pipe selection is made. Of these, an assessment of the site conditions is the most important consideration to determine the suitability of a given pipe for the project.

Many of the newer developments in pipe technology were created in the water supply and drainage industry since these applications are more numerous than hydro power. These pipes are generally available only in smaller sizes, but usually within the size ranges required for a small hydro power scheme.

The different types of penstocks are compared in Table 2.5; typical diameter and pressure ranges are shown in Appendix 3, Figure 3.5.2 and typical costs and diameters for 700 kPa/100 psi are shown in Figure 3.5.1. The following types of pipe and installation techniques are available for use in small hydro power systems.

Wood Stave

Wood stave pipe is a versatile penstock material in that the pieces are easily transported, curves can be built in, and higher pressures can be contained by using more steel hoops. It is available in a wide range of sizes up to 6 metres in diameter. It has some disadvantages in that it is labour intensive to construct and has a life span of about 40 years, depending on the environment. The individual staves are staggered when placed and ends are butt jointed together using metal butt connectors or finger joints machined in the wood. The pipe must also be supported at frequent intervals if it is not buried.

Steel

Steel pipe can be used in all size ranges and its principal benefits are its strength and versatility. It can be installed using standard welding techniques and can be unsupported over long spans. Flange joints can also be used. It also has some disadvantages especially when exposed. It must be protected from corrosion and the support system must absorb the stresses and movement resulting from thermal expansion. The weight of the pipe means that even in small sizes it must be put in place by machine methods. It has a life span of more than 60 years with suitable surface protection and maintenance.

Concrete Cylinder Pipe

This form of pipe combines the tensile strength of steel with the compressive strength of concrete. It is factory made in standard diameters and is fitted together using a bell and spigot joint. Because of the joint system and relatively heavy weight it is preferable to bury the pipe. The pipe can be installed relatively easily if heavy lifting equipment is available, but installation is more difficult over rough ground. Concrete pipe has a long lifespan.

Ductile Iron Pipe

Ductile iron pipe would be the same type as used in waterworks. It is available in diameters up to 0.6 metres and is heavy and durable. It is bell and spigot jointed, hence burial is the preferred installation method. Pressure ratings are up to 2450 kPa/350 psi and the lifespan is in the order of 50 years.

PVC Pipe

PVC pipe has many of the properties of ductile iron pipe except that it is not subject to corrosion and is lighter in weight. Pressure ratings are typically to 1400 kPa/200 psi and the joints are bell and spigot. It should only be considered

TABLE 2.5

PENSTOCKS

Sheet 1 of 2

Type	Application and Advantages	Disadvantages
Wood Stave	- Will handle corrosive waters - Flexible, can take short spans - Can be assembled without machines - Does not require large anchors to restrain expansion	- Leakage is common - Expensive to purchase pipe - Lifespan is less than other types of pipe
Steel	- Can be custom welded - High pressure rating - Can be used on long spans	- Must be protected from corrosion to ensure long life - Expensive to install - Needs expansion joints to handle thermal expansion
Concrete Cylinder	- Installed with slip joints - Not subject to corrosion	- Heavy - Must be buried
Ductile Iron	- Slip joints, easy to install - Relatively inexpensive	- Can be corroded - Must be buried
PVC	- Light, easy to install - Smooth inner surface low friction	- Must be buried (sensitive to ultraviolet light)

TABLE 2.5

PENSTOCKS

Sheet 2 of 2

Type	Application and Advantages	Disadvantages
Polyethylene	- Available in many sizes and pressure ranges	- Must be restrained from excess thermal movement
	- Able to tolerate pressure transients	
	- Easily curved	- Expensive
	- Can be buried or above ground	
	- Light weight	
	- Can be pre-assembled and dropped or dragged into place	
	- Smooth, not subject to corrosion	
	- Not damaged by freezing	
Fibreglass Pipe	- Pipe sections can be custom made or manufactured to standard sizes	- Should be buried to 50% of the diameter or more
	- Light weight, easily placed	- Expensive
	- Smooth, not subject to corrosion	

for buried installations because it is sensitive to ultraviolet light, but the lifespan could approach 100 years. With proper protection from uitra violet light, solvent welded couplings (glue joints) could be considered for above ground installations.

Polyethylene Pipe

Polyethylene pipe is finding increased uses in small hydro power installations. It is light, flexible, suited for above ground installation and easy to install. It is available in pressure ratings to 1400 kPa/200 psi. Polyethylene pipe is especially economical where it is used in the low pressure part of the penstock. It is available in diameters up to 1.5 m, although the full pressure rating is only carried up to the 0.4 m size. It can be jointed using thermal butt fusion or flanges, and the lifespan would approach 100 years.

Fiberglass Wrapped Pipe

Fiberglass is a newer pipe material. It can be factory or field manufactured to diameters of 6 m and is not subject to corrosion. It is also easily modified for customized conditions and is light in weight. It is best suited for buried situations, to pressures of 1050 kPa/150 psi. Manufactured sections, which include fibreglass wrapped PVC, can be curved gradually in a trench and are sometimes available to 2450 kPa/350 psi rating. Joints are most often bell and spigot, but flanges can be supplied.

Penstock Supports

There are several types of penstock support available which are used for different conditions of topography and pipe material. The simplest and best support is the ground, which can be used for all pipe types (preferably with full burial). Ground support provides uniform pipe support, restrains pipe movement and protects the pipe from external damage.

When the pentock must be placed on or above the ground the support system must be carefully designed. Pipe material, water pressure, span and support size must all be considered. In general, supports for above ground pipes are only practical where the pipe is continuously jointed or where frequent support intervals are tolerable. Pipes most frequently using support systems are steel, polyethylene, wood stave and glued PVC. Some support types are listed below:

- concrete pedestals for small diameter steel or polyethylene;
- steel pedestals with half steel cylinder for steel pipe;
- wood frame supports with saddles for polyethylene or PVC;
- wood or steel cradles for wood pipe.

As systems get smaller, the types of support can become more innovative and less expensive as long as the owner of the project is prepared to spend time on repair and adjustment.

Penstock supports are used mainly for straight sections of pipe. Where sharp bends are involved the pipe must be restrained from thrust forces by an anchor block. Hydraulic forces and thermal expansion forces (especially with steel pipe) are concentrated at these bends, and restraint in the form of rock anchors or mass concrete must be provided. The design of anchors can only be optimized by considering all the site conditions.

2.8 DAMS AND INTAKES

Every small hydro power project must have a means of creating a head of water above the turbine, to allow the potential energy in the water to be utilized. This can be done with a dam or a gathering intake, depending on the topography. Other purposes of the dam or intake include water storage and providing for inlet conditions.

Dams

Dams can be constructed in all heights and configurations. Simple dams, sometimes made of timber cribbing, can be used for low heads and very small installations. However, a properly constructed earthfill or concrete structure is preferable to avoid long term maintenance and replacement costs.

Most small hydro power projects, in order to be economic, cannot depend on a dam for all of the head, so the water is carried to a lower elevation in a penstock. There will probably be a few ideal situations where a dam alone can create enough head with sufficient water for an economical project, but these are rare.

Intakes

The more common type of system for the high head power sites prevalent in British Columbia is the run of river intake. This is a relatively simple structure located within a stream. There is only a small amount of water impounded, which will not smooth out daily flow variations.

The intake should be designed to allow bedload from the stream to pass by the structure while water is admitted to the penstock. A shallow, low flow diversion weir is often provided so the inlet is deep enough so that ice problems and vortices are not created. The structure itself must be durable and securely anchored to the ground. There must be a shut off valve followed by an air vent near the inlet. Trash racks and/or screens are located on the outside of the intake structure to prevent bedload or debris from entering the penstock. (Sometimes heating is added to trash racks to prevent ice build-up). Settling tanks or ponds are often provided to remove finer sediments.

In the run of river intake it is important to allow for future maintenance if bedload accumulations are possible. There must be a means of cleaning out sediment and of servicing the screens and valves of the intake. Relatively easy access to the intake must also be provided for the operation of the inlet valve, and there should be a water level gauge which can be read to determine stream flows.

Another form of intake is the drainage gallery. This system avoids the trash rack because water is admitted through pervious soil to a sump, from where the penstock originates. The system requires a large diameter infiltration pipe and is very sensitive to soil permeabilities. The advantages are that the drainage gallery intake can be located away from the watercourse and thus protected from ice and debris. The disadvantages are that a large collection area may be required and that the soil may become clogged with fine sediments, especially if a permeable filter bed is installed that is much cleaner than the natural soils of the stream bed. It is usually impossible to clear a clogged intake by applying back pressure to the penstock.

All types of intakes can have water level control and sensing devices installed. These can activate the governor or control valves to ensure that the intake level is maintained during periods of low flows. The output of the plant would be reduced accordingly. Typical intake details are shown in Appendix 3, Figure 3.6.

2.9 POWERHOUSE FEATURES

The design and location of the powerhouse is dependent on the site conditions, but its interior configuration is mainly dependent on the turbine and generator sizing. Hence the powerhouse design cannot be confirmed until the principal dimensions and requirements of the turbine and generator are established. This information is only available after consultation with the manufacturer.

Once the turbine and generator sizes have been determined, other components are fitted into the remaining floor space. Some components, such as the governor and shut off valve are closely related to the turbine location, while office, washroom, and switchgear area can be located with fewer constraints. Powerhouse cranes are expensive, but highly desirable for installation and maintenance of the equipment. Additional building functions, such as heating and ventilation must be considered in terms of the special requirements of the turbine and generator. Some typical building layouts for different types of turbines are shown in Appendix 3, Figures 3.7.1 to 3.7.7.

3. RESOURCE ASSESSMENT

3.1 BACKGROUND

A small hydro power scheme, for the purpose of this assessment, is defined as having an installed capacity of less than 20 MW. This definition conforms with the regulatory guidelines of the British Columbia Public Utilities Commission, which has streamlined the application and approval process for projects in this range.

The definition of a hydro power site as "small" is strictly a relative one. In British Columbia, where there are many large hydro power developments, 30 percent of the sites operated by BC Hydro are in the small category. Some of them may be physically quite large with generators 3 m in diameter. However, their total installed capacity is only 0.8 percent of the total capacity in the province.

The relative magnitude of the small hydro power resource must be put in the proper perspective for its importance to be appreciated. Although the energy potential is relatively small for a single site, the overall total energy potential can be significant especially when comparing the cost of developing small hydro with that of diesel power, or with new large scale projects. Furthermore, the geographical area which can be served by development of small hydro power potential is large because of the numerous sites available and the relatively low power requirement of the small communities near the sites.

Small hydro power has several inherent advantages to the community and the overall power system. The small physical size implies a relatively low impact on the environment. Many schemes, especially run of river systems, use a section of river channel that is not frequented by fish and there is only a small impoundment of water at the intake. Transmission lines are usually of lower voltages and involve simple pole type construction. The advantage to the power system is that the power sources become dispersed and less dependence is placed on a small number of power stations and river basins to supply the demand. The schemes also use a local renewable energy resource which would otherwise be untapped.

The resource assessment part of the study was directed at cataloguing the small hydro power sites that could be connected to the integrated provincial grid, dominated by large hydro power sources, or to the numerous isolated communities presently served by B C Hydro diesel generators.

The following sections described the methodology for evaluating the small hydro power resource.

3.2 PROJECT AREA

As indicated in Appendix 1 the area analysed in the study covers most populated parts of British Columbia. Emphasis was placed on finding small hydro power sites which could be connected to the main distribution and transmission lines of B C Hydro and West Kootenay Power and Light. Also included was a study of potential sites where B C Hydro operates diesel generating plants.

Limitations were put on how far from existing transmission lines the small hydro sites could be located. It was assumed, on the basis of preliminary economic calculations, that the furthest a 20 MW site could be away from the grid was 150 km. Smaller sites within this limit were also analysed to cover the possibility that a future transmission line may pass nearby. Isolated coastal areas were not analysed, as these were covered in a previous study (Crippen 1980). However, all areas near isolated B C Hydro diesel plants were covered to a distance which would approximate the economic limit of the appropriate small hydro power system.

There were several levels of mapping available for the project. Most of the developed areas of the province are covered by Provincial Lands Branch mapping at scales of 1:125,000, 1:126,720 and 1:100,000 with contour intervals of 200 feet, 100 feet and 50 m respectively. These maps cover the areas south of latitude 51°N plus the Fraser River to Prince George. Where supplemental mapping information was needed, Federal Government 1:50,000 topographical maps with a contour interval of 100 feet were used. For the purposes of the study, all units were converted to metric.

The above levels of mapping provide good information on the regional features and basin areas, however the contour interval limits investigation to sites of 30 m (100 ft) or more in elevation difference. There are likely to be a few sites available where there is a waterfall of less than 30 m or an unusually steep section of watercourse. Unless there is a specific elevation given beside the name of the waterfall, these sites cannot be analysed with this level of study. However, there is enough information in the report to determine the power potential and approximate cost of such sites, based on a knowledge of the head and slope.

3.3 EXISTING SITES

There are approximately 212 small hydro power sites licensed by the Water Rights Branch to use water for power generation. Of these, 59 are registered with an authorized installed capacity. B C Hydro operates 9 of them, while the remainder are privately owned and range in size from 3 kW to 13,320 kW. Of the 50 private sites with an authorized capacity, 40 actually have generators installed. It is not certain how many of the above sites have been abandoned.

Some of the sites mentioned have been in existence since the early 1900s. It cannot be certain if they are sized to the optimum capacity for the site, as the hydrology information used was probably based on a small amount of data. In many areas the potential of a creek is clearly not fully utilized, but then the circumstances of the plant developer may have dictated a small power requirement. Most of these projects were installed in remote areas where there was small demand for power and at a time when there was no provision in the utility regulations for private generation. In cases where the basin flow is under utilized, the proposed sites in the study are superimposed on existing sites, with the total basin capacity shown.

3.4 HYDROLOGY

The determination of the hydrology of the areas under investigation involved the collection of data from several sources. This information was supplemented by a study to determine the firmness of flow and the optimal installed capacity of a plant, thus enabling all projects to be compared on the same basis.

Most projects will be run of river plants and the choice of installed capacity is not obvious. In such situations it would not be rational to construct a plant large enough to utilize the peak flows, otherwise it would be operating at far below capacity most of the year. Alternatively, to size the plant for the firm flow of the creek (which is difficult to judge at best) would mean that the project is wasting water most of the year.

In order to better assess the problems of sizing the plant, several basins were analysed in different regions of the province. Project costs were estimated for various installed capacities and the energy available at each installed capacity was determined. Then the cost per kilowatt-hour was computed for each installed capacity. It was found that in all cases the cost per kilowatt-hour decreased as the installed capacity met and exceeded the mean annual flow. For en installed capacity sized for the mean annual flow, the average annual energy production was found to be in the range of 40 to 80 percent of the theoretical capability of the plant.

The implication of the findings was that the installed capacity of a plant should be sized on the basis of 80 to 120 percent of the mean annual flow. The results showed conclusively that sizing the plant for much too small a capacity greatly increased the cost of energy. The question of optimal plant sizing is then based on the following parameters:

- How much power can be utilized by the local system and at what time of the year?

- How much can the plant owner afford to pay for the installation?

- What materials and equipment are available?

The resource assessment used the mean annual flow as the basis for sizing all of the plants. The firmness factor was used as a measure of the energy available as a percentage of the theoretical annual energy. This information can then be used to compare plants on the basis of their cost in cents/kW.h.

The values for mean annual flow were determined from a map of mean annual rainfall in British Columbia (converted to a runoff in l/sec/km^2) from mean annual runoffs (l/sec/km^2) at many gauging stations throughout the province. Where a basin under investigation had similar topographic characteristics to an adjacent gauged basin the same unit runoff was used multiplied by the basin area. Where a basin covered a different precipitation zone as indicated by the precipitation map, the flow at an adjacent gauged basin was adjusted to allow for the change in precipitation. An example of the procedure is given in Appendix 2.

3.5 MAP STUDIES

The main effort of the study was put towards basin analysis. The various maps which had been collected were studied individually to determine the magnitude of the parameters required for each potential hydro power project as follows:

Basin Area: The basin area was measured using an overlay grid, direct measurements or by planimeter. The location of the intake was assumed and only the area above the intake was measured. The area was multiplied by the mean annual flow as determined in Section 3.4.

Gross Head and Penstock Length: The contour information was studied with a view to locating the penstock in an optimum location. The slope was maximized in order to reduce the length of penstock and the intake was located at the top of the steep section. Without the benefit of a site specific study, the contour information was assumed to be accurate and the distance of the penstock was measured on the map. The exact location of the intake will also depend on site conditions, with preference shown to areas that will minimize bedload and ice problems.

Generally, the penstock was located in an area with a stream slope greater than 10 percent, (10 vertical units to 100 horizontal units, or about 6 degrees), since the economics become unfavourable for lesser gradients. Some difficulty was encountered with evaluating low head plants because information on the available mapping did not always show a waterfall or steep section. If such a change in grade occurs between two adjacent contour lines, a potential site can be found only by an air photo study or local knowledge. In the cases where a waterfall of uncertain height exists, the report describes the site and gives the flow, so that the power output can be calculated when the waterfall height is determined. In areas that are using diesel generated power, lesser stream gradients were analyzed, as low as 5 percent.

Distance to Transmission Line: As the purpose of the study was to locate projects that can be tied into existing transmission lines, it is important to know the voltage rating and proximity of the nearby transmission lines. This information was obtained from transmission and distribution line mapping provided by B C Hydro and West Kootenay Power and Light and plotted on the contour maps.

The distance to the existing lines was scaled off the map, following roadways where possible. The voltage rating of the interconnecting transmission line would be determined by its length, power input, and in some instances by the voltage rating of the existing line.

Access Road. Most sites are located fairly close to existing secondary roads. However there are some areas where new roads must be provided for construction and maintenance, and others where the size of the installation will require road upgrading. These factors were considered when the access road distance was measured.

Site Factor. The site factor was applied to the standard unit costs used in the cost analysis program. It is based on a judgement of the conditions of the site and can range from 1.0 for sites with good access located near large towns to 1.5 for sites that are remote without support facilities. The increase reflects the higher costs that a contractor will face on isolated jobs.

3.6 DESIGN STANDARDS

After determining the basin parameters as in Section 3.5, this basic information was assembled and input to a computer program. The program calculated the approximate dimensions of the main project components, as discussed below.

Installed Capacity: The installed capacity was based on the mean flow and the head using the formula: Gross Head (m) x Flow (m^3/s) x 7 = Capacity (kW).

Intake: The intake was sized in proportion to the flow in the penstock and provided with sufficient trash screen area to admit water at less than 0.6 m/sec. The intake is the most difficult component to estimate because its configuration is mainly site specific.

Penstock: The penstock was sized to allow a maximum head loss of 10 percent or a maximum velocity of 3.8 m/sec. The design was based on using steel pipe, which can be used in any situation. This simplifies the cost calculation when there is little site specific information available. The pipe was sized to have a minimum 6 mm wall thickness. Support structures (anchor blocks and pedestals) were assumed to occur at intervals of 12 metres along the penstock. This would vary with the actual elevation and thickness of the penstock. A surge tank was not included, because it usually amounts to only about 5 percent of the penstock cost, if it is required.

Turbines: Each project was designed for one turbine with a generator running at a synchronous speed. General design text guidelines were used for choosing a speed and type of turbine with due consideration of the cavitation limits. A selection table was incorporated into the computer to choose a speed and turbine type from the head and flow information.

Powerhouse: The powerhouse sizing is mainly dependent on the turbine and generator size. At this level of study horizontal shaft units were assumed, which maximizes the floor area used. The building was sized for unattended operation, that is, only the essential facilities are provided with no conveniences for the plant operator.

Power Transmission: Feederlines run from the generating plant to the nearest point of connection to existing transmission lines and it was assumed that interconnection with the existing system can be made at these points. Details of the electrical interconnection are not included at this level of study.

Transmission line information is shown as if only one project were constructed. In fact, there could be several projects in an area which could benefit from the installation of one line. These details would need to be determined when projects are brought to the design stage.

3.7 PROJECT ANALYSIS

Once the basin parameters (through the map study) and the design standards (calculated from basin parameters) have been determined, a small hydro power project has been conceptualized. It remains to account for some less obvious factors that go into the decision to proceed with a site specific feasibility study.

The location of the project is probably the most critical factor. The stream between the intake and the powerhouse should not be a migratory area for fish. If the location infringes on a park, the Parks Branch approval would be required, and other land conflicts with forestry, private and crown land must be settled.

The relationship of the project with respect to the nearest transmission or distribution line is important because the characteristics of the system at that point can affect the overall project cost. Interconnection will have to be made at a compatible system voltage, within the capacity of the existing lines and using equipment and practices approved by the utility. The purchasing utility must be contacted at an early stage to determine its interconnection policy.

Accessibility must be a concern for the owner of a project, as the plant must be serviced and maintained. The size of a project is relevant, because for a small plant the effort to maintain it may not be justified if it is too remote. Winter maintenance is also a concern in isolated or mountainous regions, both for the effects of cold on the plant and increased difficulty of access.

A site inspection must be carried out at an early stage in the project. Map studies must be improved by air photo analysis, which combined with a site inspection would indicate landslide hazards, bedload conditions, foundation conditions and the overall characteristics of the terrain.

The economics of the project, which will partly determine whether construction can proceed, will be determined at several levels of the study. As each stage of the study is completed, the costs and benefits should again be evaluated. Economic parameters derived from the initial stages are described below:

Mean Project Cost: The computer program calculates a mean cost for each project, based on the best estimates of the site parameters and the cost indices which are built into the program. Separate cost curves were used for the intake, penstock, powerhouse (including equipment), access road and transmission line, although the transmission line cost is not included at this level of study. A contingency allowance and the cost of engineering are applied as percentages to the total construction cost.

Mean cost/kW.h: The mean project cost calculated above is divided by the average annual energy that could be generated, and multiplied by the assumed discount rate of 5 percent. The discount rate is defined as the rate of interest minus the rate of inflation. This is a means of ranking projects but the actual cost would depend on how the project is financed.

Cost Range/kW.h: The data input into the computer program is adjusted for the uncertainty in the hydrology and cost information. The estimated mean annual flow is given a range, depending on the proximity of a gauged basin and the length of record. This information also affects the firmness of flow, which is used to derive the average annual energy available. Further uncertainties are applied to the cost estimates and the discount rate to get a range of cost/kW.h. There are other uncertainties which exist in the project analysis, and these can only be evaluated with more detailed study, especially site investigation. Contour intervals on the maps limit the accuracy to which the gross head can be calculated, and also the determination of the penstock length. More accurate mapping and a site inspection would also assist in determining the drainage area and in visualizing any construction difficulties.

4. PROJECT FEASIBILITY

4.1 INTERCONNECTION POLICIES

Small hydro power sites can be developed strictly to suit the needs of the Owner or for serving a larger power market. The feasibility of the former type of project will depend on the Owner's resources and alternative power sources. Projects serving a larger market, which in this study is defined to be the provincial electric grid, require a definitive interconnection policy provided by the local utility, covering the technical and commercial aspects of small hydro power projects and distinguishing various size ranges.

Most of the background information is available from United States sources. The status of small hydro power development in the United States is such that the development of the resource is ahead of British Columbia in respect of utility interconnections, although British Columbia has its share of isolated systems. Most United States utilities have developed their policies based on the PURPA (Public Utility Regulatory Policies Act) legislation. A few examples of these policies are described as follows:

Oglethorpe Power Corporation (Georgia) (OPC)

The interconnection policy of the Oglethorpe Power Corporation is limited to qualifying facilities (QF) that produce power directly or through cogeneration with the facility meeting FERC (Federal Energy Regulatory Commission) rules. Legally the utility must cooperate with the qualifying facility but it has considerable say in the design and operation of such facilities.

Technical System Guidelines including Interconnection Practice, Protection, Metering and System Operating Requirements are all clearly covered in the Oglethorpe Interconnection Policy Manual. Technical requirements vary with the size of plant, system connection and voltage rating of the associated transmission or distribution lines. Installations are broken down into six main classifications recognizing different operating characteristics and protection requirements as follows:

Type	Generator Size	Phases	System Connection	Power Interchange Either Direction
1	5000 kW or greater	3	Network Line	Yes
2	5000 kW or greater	3	Network Bus	Yes
3	5000 kW or greater	3	Radial Line	Yes
4	101 - 5000 kW	3	Radial Line	Yes
5	11 - 100 kW	3	Radial Line	Yes
6	0 - 10 kW	1	Radial Line	Yes

Generally speaking, OPC provides all interconnection facilities, at the expense of the QF, including all protective and metering equipment which OPC owns, operates and maintains. The QF designs and provides the generating system subject to OPC approval.

Qualifying generation facilities enter into a written contract with OPC. Rates governing the purchases of capacity and energy are established by OPC for the smaller capacity installations and arrived at by negotiation for the installations over 5000 kW. OPC reserves the right to conduct a special analysis of the cost impact and to adjust the rates accordingly.

Seattle City Light (Washington) (SCL)

The policy of Seattle City Light is to interconnect with qualifying small power and cogenerating facilities and to make possible the purchase and sale of electricity. Their policies and procedures which are based on PURPA legislation are presently only available in draft form. They provide the prospective power producer with general information on the approval process, design and installation requirements in conjunction with a separate document, entitled **Interconnection Requirements.**

All electrical apparatus required to control the generator and to tie it into the Utility System at the point of interconnection, including transformers, switchgear and protective relaying are furnished, installed, operated and maintained by the qualifying facility.

Utility equipment required for the interconnection, including metering, is provided and maintained by SCL. Design and specifications of the complete installation are subject to SCL review and approval.

Power is purchased under contract and rates are set in accordance with avoided costs for energy and capacity.

Portland General Electric Company (Oregon) (PGE)

The interconnection requirements of the Portland General Electric Company are simply stated in their regulations, **Electric Service Requirements for Single-Phase and Three-Phase Parallel Generation.** Subject to design approval, they provide for customer owned generation to operate in parallel with their system where the customer provides all of the electrical apparatus required for generator control, protective relaying and interconnection. Regulations are now available for the connection of systems less than 100 kW, and regulations are being drafted for larger systems.

B C Hydro (British Columbia) (BCH)

The cogeneration and interconnection policies of B C Hydro have not been finalized. In the light of revised load growth forecasts, the utility is taking a cautious approach to the subject of interconnections to the provincial grid and a definitive policy was not available. In areas that are presently served by diesel generation, there are some better defined cost savings to be made if small hydro power systems can be connected. B C Hydro will evaluate proposals and negotiate rates of payment in diesel areas on an individual basis.

West Kootenay Power and Light (British Columbia) (WKPL)

West Kootenay Power and Light Company serves many communities in southern British Columbia from Kelowna and Keremeos to Creston. They encourage the development of small hydro power sources, as the system must rely on transfers of power from the B C Hydro system to meet its peak demands. The technical requirements are typical of most utilities, where protection of the overall system and the customer owned generator must be coordinated (and paid for by the customer). Initiating the process to satisfy the technical, legal and commercial terms can be done at any of the district offices. WKPL rates will be variable as to the time of day and the time of year.

4.2 WHEELING POWER

The concept of wheeling power is not new but its application to small hydro power projects in British Columbia has not yet been tried. Wheeling involves the transfer of power from a producer to a customer, through the tranmission lines of a third party (utility) not directly involved with the other two. Both B C Hydro and West Kootenay Power and Light supply power to California customers through the transmission lines of Washington and Oregon. All of the West Coast utilities from California to British Columbia are in the Northwest Power Pool and these arrangements benefit all of them at one time or another, as firmer power supplies are established. The cost of transmission is nominal and paid to the utility wheeling the power.

It may be possible for a small hydro power producer located in the B C Hydro system to establish a contract with West Kootenay Power, who would take the appropriate amount of power through their interties with B C Hydro. The small hydro power producer would still have to meet the technical requirements of the utility to which it was directly connected. In order for this arrangement to be widely used, definitive policies will need to be established by both B C Hydro and West Kootenay Power and Light.

In the extreme, a private power supplier with a need for power may be able to wheel power to itself, using the stability of the utility to control its self generated power. A two way arrangement of power transfers would need to be arranged so that when the utility fed power in the normal billing would apply, while when the supplier fed power out it would displace the suppliers own need for power. Even if the utility did not pay for power supplied, there could be advantages to the supplier if the supplier's generator was well matched to the supplier's loads.

4.3 COST ESTIMATES

The capital cost of each small hydro power project was based on a combination of experience curves, cost curves in literature and unit price data, all adjusted to 1982 price levels. Separate cost curves were used for intakes, penstocks, powerplants and transmission lines. Percentages were applied to the total for engineering services and for a contingency allowance.

The cost of the generating facility for a project was separated from the transmission line cost, in case the transmission line was long and created a disproportionate cost index. This permits each project to be analyzed in more detail and allows for a better rating where several adjacent projects share a transmission line or if a new transmission line is built into the area.

The cost of the power produced by the small hydro power station is estimated by taking the annual cost of the project divided by the average energy generated per year. The annual cost of the project is normally calculated by taking the cost of amortization over 40 years (the plant life) and adding in the cost of the annual maintenance and operating expenses. In this study a rate of 5 percent was used. This approximates the interest rate net of the inflation rate, and provides a practical index for comparing the potential small hydro power sites. A more rigorous analysis is provided in the companion volume to this report, **Small Hydro Power Resource in the Provincial System, Economic and Financial Assessment**.

The annual energy generation is taken as the total number of kilowatt-hours of energy which could be generated in a year. It is assumed that the plant will generate at a rate equivalent to the energy available in the water, up to the installed capacity. For run of river plants with no storage, this is taken as the theoretical annual energy (based on full generation at the installed capacity) multiplied by the firmness factor (which accounts for the periods when there is insufficient flow to meet the installed capacity). The resulting cost of power (in cents per kilowatt-hour) is a means of comparing different sites with a common parameter, and relating the cost to current rates payable for power. Once a project has been studied further, the actual unit cost of power must be determined by a more detailed financial analysis.

4.4 REVENUE ESTIMATES

The preliminary analysis of the small hydro power project must estimate the annual revenue of the project for comparison with the annual cost. It is assumed that the rate of payment for power supplying the provincial grid may be about 2 cents/kW.h (1982), but this rate has not been fixed by either B C Hydro or West Kootenay Power and Light. The rate of payment must be modified by the water tax, currently set at .314 cents/kW.h (1982) and payable to the Provincial Government. Where the small hydro power system is supplying a diesel powered system, (where the cost of energy is at least 10 cents/kW.h), the rate of payment should be set much higher to reflect the avoided costs of the utility. Section 27 of the British Columbia Utilities Commission Act allows the BCUC to rule on rates paid to private suppliers.

The theoretical annual revenue is found by multiplying the net rate of payment by the installed capacity, the firmness factor, and the number of hours in a year (8760). The actual revenue would be less than this to account for production losses during maintenance and repairs. Therefore over the long term, the actual revenue should be about 90% of the theoretical, assuming that the utility will accept all of the power that the small hydro power installation can produce.

4.5 FINANCIAL CONSIDERATIONS

The financial feasibility of a small hydro power development can be evaluated in the same way as any capital investment that produces a stream of benefits as a cash flow.

As a project is conceived and designed, it should be analyzed for its economic feasibility at each step. The comparison of present value costs to present value benefits should be the main criteria in making the decision to proceed to the next stage of investigation. Feasibility can also be determined by comparing the internal rate of return on investment to a target rate.

A preliminary analysis has revealed it is possible for a small project to be financially feasible even if it experiences a few years of negative cash flow at the beginning. Taxation benefits or penalties and possible government assistance will influence the feasibility of the project.

Further discussion of financial feasibility is beyond the scope of this study, and is covered in the companion report.

5. MAGNITUDE OF THE SMALL HYDRO POWER RESOURCE

5.1 POTENTIAL SMALL HYDRO POWER SITES

The potential small hydro power sites covered by this study are listed in the tables of Appendix 1. Each group of tables is keyed to a map in Appendix 1. The key parameters used to evaluate each site are described in Sections 3.5, 3.6 and 3.7 and are listed in the tables in Appendix 1.

The 665 small hydro power sites analyzed have a total possible installed capacity of 1439 MW. These are separated into grid power areas and non-integrated diesel areas as shown on the maps in Appendix 1. The regional totals are shown in Table 5.1. Determination of potential power output in the remainder of the province was beyond the scope of this report, but an estimate was made based on power availability in adjacent areas that were analysed.

Grid Power Areas: The number of potential sites which could be connected to the grid is estimated at 553 with a total capacity of 1189 MW. These sites have not been ranked according to their economics, although the cost indices indicate which are the more attractive sites. For the purposes of this study, only those sites with an installed capacity greater than 100 kW were catalogued. Based on the proportion of existing plants less than 100 kW to the overall total, it was estimated that a further 35 MW of capacity may be available in sites with less than 100 kW capacity.

Diesel Power Areas: Investigations were carried out in the areas served by non-integrated BC Hydro diesel generators. The total capacity located within these areas is about 250 MW in 112 sites, as shown in the Tables. BC Hydro's avoided cost of generation in these areas is 10¢/kW.h or more, hence the economic limit of these plants is much higher than in grid areas where the net power value could be about 2¢/kW.h.

Isolated Areas - (Not Connected to Power Distribution Systems): Based on the area covered by the grid and diesel regions, a rough estimate of the remaining provincial potential for small hydro power is 954 MW. Many of these areas not covered by the grid and diesel assessments in this report are inaccessible or so remote as to not require power in any quantity. The estimate must be treated with caution as it is statistically derived and the development of the resource in these areas is uncertain.

5.2 WATER LICENSES HELD AT UNDEVELOPED SMALL HYDRO POWER SITES

As indicated in Section 3.3 there are about 150 sites which are licensed for power production by the Water Rights Branch, but which currently have no record of having generators installed. It is known that some of these sites do have generators installed but it is considered that most of the locations are categorized correctly. The total flow licensed is about 11 m^3/s or an average of 70 l/sec per site. This is not a significant amount but any subsequent development on the same creek would have to consider the prior rights of the first licence holder.

These licensed locations are generally owned by individuals, and are a mixture of remote sites and sites which may be close to existing distribution lines. The parties holding these licences were in most cases considering only their own power requirements when they applied for their licence, hence they would usually have little water available for use in generating power to be sold.

TABLE 5.1
SMALL HYDRO POWER SITES IN BRITISH COLUMBIA

Integrated (Grid) and Non-Integrated (BC Hydro Diesel)

Region	Number of Sites	Capacity MW	Energy GW.h/yr
1	146	271	1150
2	146	510	2508
3	161	215	1220
4	45	80	348
5	26	81	423
6	23	86	489
7	23	40	174
8	39	58	303
9	19	30	179
10	0	0	0
11	24	47	230
12	0	0	0
13	13	21	78
TOTAL	665	1439	7102

SMALL HYDRO POWER SITES
NEAR EXISTING B C HYDRO DIESEL GENERATING SYSTEMS

Region	Number of Sites	Capacity MW	Energy GW.h/yr
3	29	23	111
5	21	79	415
6	23	86	489
7	15	26	112
9	5	42	24
11	6	12	56
13	13	21	77
TOTAL	112	250	1,284

NOTE: The number of sites listed above and in the tables of Appendix 1 represent the first approximation of the resource, based on mapping of limited detail and generalized hydrology patterns. The viability of any scheme can only be determined after field investigation, detailed hydrology study and detailed financial analysis.

5.3 EXISTING SMALL HYDRO POWER INSTALLATIONS

As discussed in Section 3.3 there are about 49 sites with licensed generation capacity and machines installed. In this section a few case studies are provided as examples of the range of sizes and interconnections covered by small hydro power development.

Shuswap Falls Generating Station
5200 kW - BC Hydro

This station is about 50 years old and takes advantage of a natural waterfall in the Shuswap River. At one time it supplied the electrical needs of the North Okanagan, but now it supplements the grid, as it has insufficient capacity for the entire area. The plant has some flow regulation provided by a storage dam 17 miles upstream.

The basic system components include a concrete arch storage dam and spillway channel blasted from rock. Twin 2.4 m diameter wood stave penstocks lead to the differential surge tanks and the concrete powerhouse. Within the powerhouse are two vertical shaft turbine generator units, rotating at about 225 RPM and rated for 24 m head. Power is fed to the grid via a 10 mile long, 25 kV tie line.

Clayton Falls Generating Station
700 kW - BC Hydro

This station, about 20 years old, supplies a mixed hydro/diesel system at Bella Coola. Most of the time it is locked on to its full output, but occasionally it must swing with load variation while a diesel is locked on a fixed load.

The system consists of a river intake, and a 750 mm diameter wood stave penstock leading to a steel frame powerhouse. A horizontal shaft Francis turbine is used to turn the 720 RPM generator which feeds power to the switchyard 6.5 km away at the diesel station.

Kingcome Hydro Power Project
75 kW (Unit 1) - Tsawataineuk Band

The Kingcome Project has recently been commissioned and is an example of a run of river, off-grid site. It supplies power to an isolated Indian village on the coast, and it is to be coordinated with a standby diesel installation. The diesel and hydro power sources will only operate in isolation, as they are not designed to run in parallel

The project features an intake in a natural pool along a creek, with a 250 mm diameter polyethylene penstock leading 2/3 of the way to the steel frame powerhouse. The remainder of the penstock is steel. The water at 150 m of net head spins a Crossflow turbine at 1200 RPM, coupled to a synchronous generator. Power is transmitted at the 2.4 kV level for 1.5 km to the 20 homes in the village.

The project is designed to be expanded, requiring only an extension of the powerhouse and the addition of a second 75 kW unit and a synchronizer in the powerhouse.

Klemtu Hydro Power Project
320 kW (Unit 1) - Kitasoo Band

The Klemtu Project is an example of an off-grid site with storage. A natural lake is controlled with a low dam, and the water drops about 260 m in a 350 mm diameter, 675 m long steel penstock to the Pelton wheel turbine. The turbine rotates at 1200 RPM to drive a synchronous generator.

The project is designed to be expanded, requiring only the addition of a second unit of about 320 kW and a synchronizer in the powerhouse. It can also be isolated and a standby diesel run during times the plant is shut down for maintenance.

6. SUMMARY AND RECOMMENDATIONS

Summary of Provincial Potential

The total provincial potential for small hydro power in British Columbia is estimated to be about 2400 MW, covering electrically integrated, non integrated and isolated areas. Much of this potential is presently too expensive to develop, but under more favourable economic conditions (higher prices for electricity and lower interest rates), the potential sites would be more attractive. There are also a number of attractive sites which, because of their isolation, are not feasible to develop until a transmission line passes closer to them.

The economic balance between sites near the integrated and non integrated systems of British Columbia is indicated by reference to Table 5.1. The number of sites near the grid is about 550 with a potential generation of about 5800 GW.h/yr while the number of sites near B C Hydro diesel generating systems is about 110 with an energy potential of about 1300 GW.h/yr. Using a value of about 2¢/kW.h for grid power, the sites near the grid could generate $116 million worth of power every year, while the sites replacing diesel at 10¢/kW.h could generate power worth $128 million per year. These values are subject to more detailed site and market investigations.

The additional 954 MW of installed capacity estimated to be located in isolated areas would produce power valued at more than 10¢/kW.h because the markets would usually have diesel power as an alternative.

The companion volume to this report, **Small Hydro Power Resource in the Provincial System, Economic and Financial Assessment**, builds on the cost data developed here in order to determine the economic feasibility and the financial viability of the resource as it applies to the integrated grid and to the BC Hydro diesel systems.

Recommendations for Implementation of Small Hydro Power Systems in British Columbia

The implementation of a small hydro power scheme involves a number of steps, requiring consultation with various branches of government, manufacturers, utilities and possibly contractors. The first step is evaluation, where the physical, technical and financial constraints of the project are assessed. As the size and value of the project increases, it becomes more important to utilize competent professional services.

Once the technical and economic feasibility of a project is assured the small hydro power producer must establish a long term contract with a utility for the purchase of power. Further development of interconnection policies by both B C Hydro and West Kootenay Power and Light are required to enable the small hydro power producer to properly assess the technical and commercial terms, which play a major part in determining the project feasibility. The concept of wheeling power between utilities should also be established so that small hydro power producers can have a wider market for their power.

When a project is conceived and a market for the power established, it remains for the prospective small hydro power producer to arrange financing, complete the design and construct the power plant. This procedure involves considerable planning, expertise and careful cost control at each step to ensure that the project is technically sound and is built for the allocated budget. Cost overruns can make the difference between a successful (profitable) and an unsuccessful project. It also becomes vitally important to ensure that the power production and hence the cash flow, are maximized. This can best be done by optimizing the plant operation to use as much of the available flow as possible, and to keep the plant in operation by adhering to prescribed maintenance procedures.

The development of small hydro power in British Columbia is at a point where there could be a significant increase in activity, given some increased awareness and the right set of economic circumstances. As a step in this direction Energy, Mines and Resources, Canada has initiated the Remote

Community Demonstration Program, which is designed to fund studies to prove out a range of alternative energy projects in isolated areas. Other incentives are available through tax savings to investors in small hydro power plants, and there is probably room for additional incentives. In the long run however, there must be clear economic advantages to the utilization of small hydro power systems, advantages that benefit the public as well as the power producer. A more detailed economic and financial assessment is presented in the companion report, but the overall outlook for the resource is optimistic in terms of the number of sites and the potential value of the energy.

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APPENDIX 1

RESOURCE MAPS AND TABLES

LIST OF MAPS

Figure	Area
1	Kootenay
2	Vancouver - Okanagan
3	Vancouver Island
4	Thompson - Columbia
5	Cariboo - Chilcotin
6	Central - Coast
7	Prince George
8	Kitimat - Nechako
9	Prince Rupert - Queen Charlottes
10	Fort St John
11	Skeena
12	Fort Nelson
13	Northwest

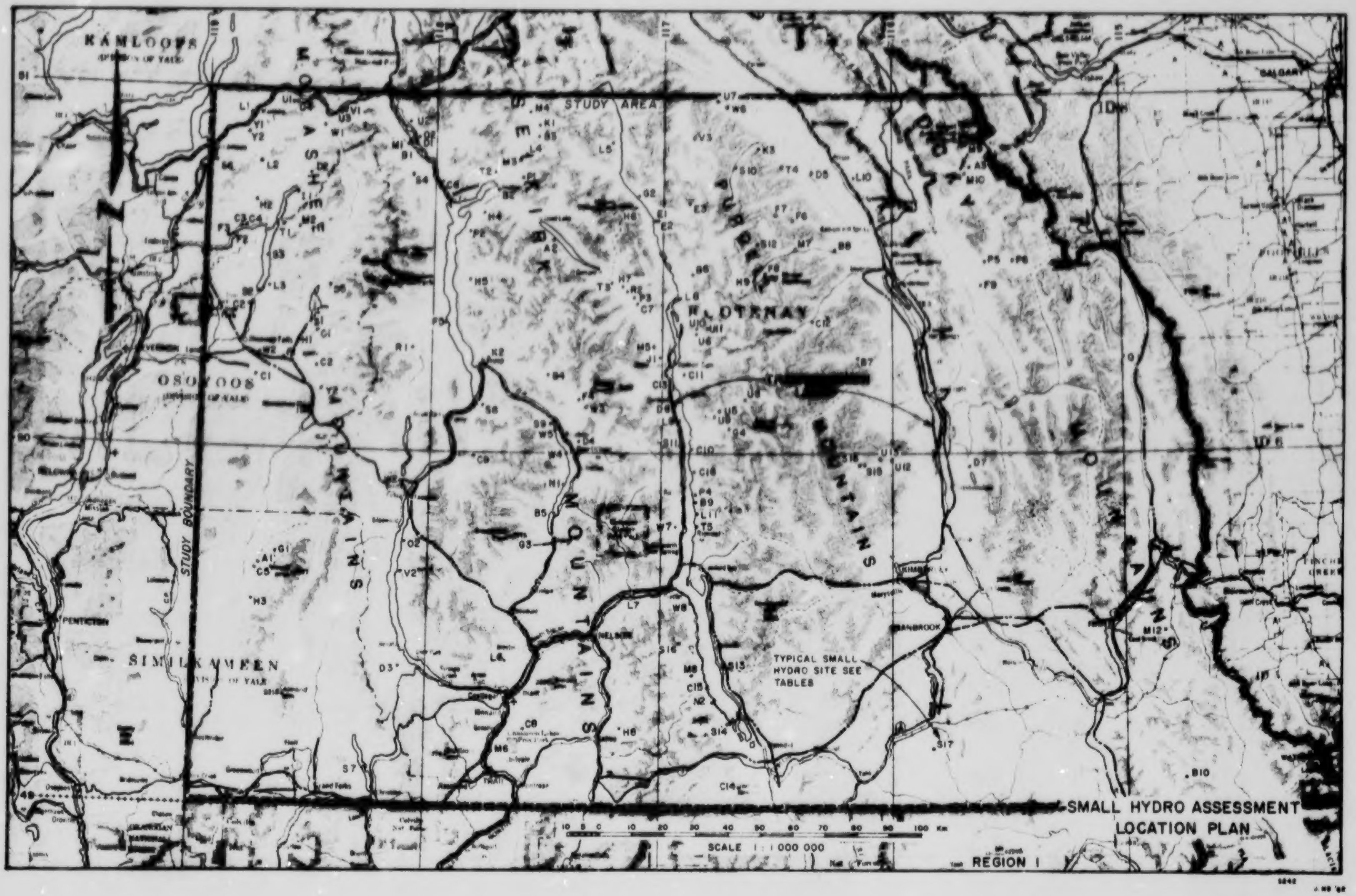
EXPLANATION OF MAPS AND TABLES

MAP DESIGNATION	DESCRIPTION
K2	Site name, begins with letter K, Numbers are sequential moving from the Northwest to Southeast.
D	B C Hydro diesel site, off grid.
Study Boundary	Indicates the boundary of the map.
Study Area	Indicates the portion of the map which was analysed for small hydro power sites.
Transmission Lines	Corridors which contain all voltages of transmission lines are shown. Where only 138 kV lines and up are present, an analysis may not have been made, because it may not be feasible to connect even a 20 MW plant.

TABLE DESIGNATION	DESCRIPTION
Lat., Long	Latitude and longitude of the site.
K2	Corresponds to a site on the map.
Basin Size	Area above the intake in square km.
Design Flow	Mean annual flow in m^3/s.
Frac. Firm.	The fraction of firmness or firmness factor. The actual energy available is the installed capacity x 8760 x Frac Firm.
Head	Vertical distance between intake and powerhouse in metres. Sites with less than 30 m of head cannot be analysed because of mapping limitations.
Pen.Len.,Dia.	Penstock length and diameter in metres.
Access Road	Length of access road in kilometres.
Line kV/D	Nearest transmission line voltage and distance. The suitability of the existing line to accept the power has not been checked.
Inst. Cap.	The installed capacity in kilowatts.
Cost ($1000)	The estimated total capital cost in thousands of dollars (not including transmission line)

EXPLANATION OF MAPS AND TABLES

TABLE DESIGNATION	DESCRIPTION
Cost ¢/kW.h	The average cost of power production based on a discount rate of 5%. For comparison only as actual costs must be based on financial analysis.
Cost Range	The uncertainties of flow, head, and construction cost are combined to give a most probable cost range in cents/kW.h.
N/A	Where waterfalls or rapids are shown on the mapping, but the height is not given, the site is shown as a potential one. Until the height is determined the remaining information is not available.


KAMLOOPS
OSOYOOS
SIMILKAMEEN
STUDY AREA
STUDY BOUNDARY
PURCELL
KOOTENAY
MOUNTAINS
MOUNTAINS
PENTICTON
NELSON
CRANBROOK
KIMBERLEY
CALGARY
TYPICAL SMALL HYDRO SITE SEE TABLES
10 5 0 10 20 30 40 50 60 70 80 90 100 Km
SCALE 1 : 1 000 000

SMALL HYDRO ASSESSMENT
LOCATION PLAN
REGION I

5642

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
ARTHURS CR A1	49 41 118 43	33	.40	.40	280	2000 .44	7.0	25 50	800	3600	6.4	2.9 14
ASHER CR A2	50 36 117 29	113	3.4	.53	150	2100 1.1	6.0	25 54	3600	9100	2.7	1.5 4.8
ASSINIBOINE CR A3	50 48 115 40	22	.53	.50	240	1500 .48	25	25 47	900	5600	6.8	3.7 12
BEATRICE CR B5	49 50 117 28	138	4.1	.45	165	750 .98	10	25 7.0	4900	5800	1.5	0.8 2.9
BEATTON CR B2	50 44 117 44	99	2.8	.63	150	2000 1.0	0.0	25 50	3000	7300	2.2	1.5 3.3
BEHRMAN CR B6	50 30 116 52	20	.70	.50	240	850 .88	5.0	25 34	1230	2500	2.3	1.0 5.2
BEN ABLE CR B7	50 16 116 09	42	.63	.50	180	1400 .53	8.0	25 33	830	3200	4.4	2.3 8.6
BERNARD CR B9	49 52 116 51	55	1.7	.45	180	1200 .75	1.0	25 20	2200	3400	1.9	1.0 3.7
[illegible]T CR FALLS	50 50 118 05	75	3.4	.45	N/A	N/A N/A	0.0	25 21	N/A	N/A	N/A	N/A N/A
BOYD CR B3	50 53 117 34	58	2.2	.53	250	1800 .84	10	25 64	4000	7100	1.9	1.2 3.2
BRENNER CR B4	50 13 117 30	77	3.5	.47	120	1900 1.2	2.0	25 26	3000	7700	3.0	1.8 5.1
BRUCE CR B8	50 34 116 15	79	2.4	.52	50	400 .88	10	25 12	850	3400	4.4	2.3 11
CAMPBELL CR C16	49 57 116 51	88	2.7	.45	240	2400 .97	9.5	25 28	4800	11000	2.9	1.5 5.6
CARIBOU CR C9	49 59 117 50	202	6.1	.45	120	1350 1.3	0.0	25 2.5	5300	7200	1.7	0.9 3.3
CASCADE CR C7	50 25 117 07	70	1.9	.47	180	1800 .84	0.0	25 14.5	2500	5500	2.7	1.7 4.3

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
CHAMPION CR C8	49 14 117 35	73	.95	.40	92	500 .58	2.0	25 4.0	630	1600	3.6	2.0 6.6
CHRISTIAN CR C2	50 24 118 48	24	.19	.45	200	900 .36	3.0	25 2.0	290	1400	6.1	1.7 23
CLINT CR C11	50 13 116 54	69	2.4	.50	243	2000 .89	1.0	25 1.0	4200	6800	1.8	0.8 4.2
CLUTE CR C10	50 01 116 53	23	.81	.50	609	3200 .55	8.0	25 8.0	3500	8700	2.8	1.2 6.5
COCHCRANE CR C5	49 40 118 44	44	.53	.40	500	2600 .47	4.5	25 45	1900	5000	3.7	1.7 8.1
COOKE CR C3	50 37 118 50	64	1.9	.45	200	2100 .86	0.5	25 0.5	2700	6200	2.8	1.1 7.4
COOKE CR FALLS C4	50 36 118 50	68	1.9	.45	N/A	N/A N/A	0.5	25 1.3	N/A	N/A	N/A	N/A N/A
COOPER CR C13	50 12 116 59	183	4.6	.47	183	5100 1.4	1.5	25 1.5	6000	29500	6.0	2.8 13
COPPERCROWN CR C12	50 22 116 21	20	.30	.50	183	1000 .41	0.0	25 24	400	1400	3.8	1.9 7.4
CORN CR C14	49 04 116 40	100	2.3	.55	60	800 .96	1.0	25 4.0	990	3200	3.4	2.0 5.8
CRAWFORD CR C6	50 45 117 59	27	1.1	.53	250	1300 .61	1.0	25 21	1900	2900	1.6	1.0 2.7
CREIGHTON CR C1	50 12 118 46	32	.30	.47	200	1800 .39	0.5	25 2.0	380	1900	5.9	2.8 12
CULTUS CR C15	49 20 116 47	168	3.9	.55	123	1800 1.2	4.0	25 27	3400	8400	2.5	1.5 4.4
DAVIS CR D6	50 08 116 57	39	.80	.47	122	500 .52	0.0	25 0.5	680	1400	2.5	1.0 6.5
DENNIS CR D4	50 02 117 22	17	.71	.45	182	1250 .55	2.0	25 2.0	930	2400	3.3	1.9 5.7

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
DERRY CR D2	50 46 118 33	44	1.3	.45	300	2350 .71	0.0	25 22	2800	5400	2.4	0.9 6.3
DIORITE CR D7	49 58 115 40	53	1.3	.40	490	4100 .72	5.0	25 2.0	4600	14800	4.5	2.6 7.9
DOG CR D3	49 24 118 07	129	1.3	.40	50	400 .71	4.0	25 35	480	2000	5.8	2.4 14
DRUMMIE CR D1	50 52 118 05	28	1.3	.45	150	700 .63	0.5	25 7.0	1300	2000	1.9	1.0 3.6
DUNBAR CR FALLS D5	50 47 116 21	69	2.4	.52	N/A	N/A N/A	0.0	25 7.0	N/A	N/A	N/A	N/A N/A
EAST CR E3	50 42 116 53	73	2.9	.52	50	500 .99	15	25 72	1000	4900	5.1	2.0 13
EAST CR #1 E1	50 39 117 02	175	7.0	.53	50	500 1.4	1.0	25 42	2500	4800	2.0	1.1 3.8
EAST CR #2 E2	50 39 117 01	175	7.0	.53	100	1150 1.4	3.0	25 45	5000	7700	1.6	0.9 3.0
FALL CR F2	50 36 118 53	15	.45	.45	500	1000 .41	1.0	25 1.5	1700	2200	1.7	0.9 3.2
FALL CR FALLS F3	50 36 118 54	15	.45	.45	N/A	N/A N/A	2.0	25 2.5	N/A	N/A	N/A	N/A N/A
FARNHAM FALLS F8	50 30 116 33	78	3.1	.52	N/A	N/A N/A	2.0	25 24	N/A	N/A	N/A	N/A N/A
FENWICK CR F9	50 28 115 37	102	2.0	.50	50	650 .91	2.0	25 40	730	3300	5.1	2.9 8.8
FERRY CR F1	50 15 118 39	N/A	1.1	.51	150	3100 .78	0.5	25 1.0	1160	6000	5.7	3.8 8.5
FITZSTUBBS CR F4	50 09 117 22	251	11	.47	60	2000 2.1	0.0	25 13	4900	16600	4.1	2.5 6.9
FORSTER CR FALLS F6	50 39 116 26	79	3.2	.52	N/A	N/A N/A	8.0	25 25	N/A	N/A	N/A	N/A N/A

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
FORSTER FALLS F7	50 40 116 30	35	1.4	.52	N/A	N/A N/A	13	25 30	N/A	N/A	N/A	N/A N/A
FOSTHALL CR F5	50 22 117 57	222	8.8	.47	60	225 1.3	1.0	25 34	3900	4300	1.3	0.8 2.3
GIEGERICH CR G2	50 43 117 07	116	4.6	.53	100	1100 1.2	1.0	25 55	3300	5900	1.9	1.0 3.5
GILLIS CR G4	50 04 116 42	50	1.8	.50	120	1200 .82	12	25 14	1500	5300	4.0	1.7 9.0
GOATSKIN CR G1	49 43 118 39	100	1.2	.50	100	1000 .71	8.0	25 60	860	3600	6.0	2.8 13
GWILLIM CR G3	49 45 117 28	80	2.4	.45	240	1100 .80	0.0	25 1.0	4200	4100	1.2	0.6 2.4
HADOW CR H4	50 40 117 48	36	1.4	.53	400	950 .59	3.5	25 41	4200	4000	1.0	0.6 1.7
HALFWAY HOTSPRINGS H5	50 29 117 51	290	13	.47	60	1300 2.0	0.0	25 22	5700	12800	2.7	1.6 4.5
HALL CR H6	50 41 117 06	44	1.8	.53	100	850 .80	0.0	25 51	1200	2700	2.3	1.2 4.2
HELLROARER CR H3	49 35 118 45	59	.71	.40	400	1750 .50	3.5	25 30	2000	3800	2.7	1.2 5.8
HIDDEN CR H8	49 14 117 10	70	1.5	.40	30	250 .75	1.0	25 5.0	330	1400	5.9	3.6 9.7
HOLSTEIN CR H1	50 18 118 35	19	.29	.45	150	1200 .41	1.5	25 1.0	315	1600	6.3	3.2 13
HOPE CR H7	50 28 117 11	23	.76	.47	240	1250 .53	0.6	25 24	1300	2500	2.3	1.3 3.8
HORSETHIEF FALLS H9	59 29 116 36	52	1.3	.55	N/A	N/A N/A	2.0	25 45	N/A	N/A	N/A	N/A N/A
HUNTERS CR H2	50 41 118 47	43	1.3	.45	150	1900 .77	3.0	25 10	1400	4500	4.1	1.5 11

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
IRON CR I1	50 43 118 36	10	.22	.47	550	2000 .36	0.5	25 22	900	2500	3.3	1.4 7.7
JOHN CR J1	50 16 117 01	23	.62	.47	180	1200 .51	0.0	25 4.5	800	2000	3.0	1.9 4.5
KAIN CR K3	50 51 116 35	34	.95	.52	250	1100 .56	2.0	25 16	1700	2700	1.7	0.9 3.5
KELLIE CR K1	50 55 117 34	46	1.8	.53	250	1150 .71	11	25 65	3100	4900	1.7	1.0 2.8
KUSHANAX CR K2	50 16 117 46	330	15	.47	60	900 2.0	0.0	25 0.0	6300	9000	1.7	1.2 2.6
LADYBIRD CR L6	49 25 117 40	156	2.0	.40	120	600 .76	1.0	25 2.5	1780	2300	1.8	1.0 3.4
LAIDLAW CR L5	50 52 117 14	49	2.2	.53	150	1400 .88	1.0	25 73	2370	5000	2.2	1.2 4.3
LASCA CR L7	49 36 117 09	64	1.5	.45	300	2100 .72	0.0	25 1.0	3200	5400	2.1	1.1 4.2
LATEWHOS CR L3	50 27 118 43	43	.65	.45	450	2600 .51	1.0	25 8.0	2100	4300	2.6	1.1 6.3
LEGERWOOD CR L2	50 58 118 46	12	.53	.45	250	1300 .47	0.0	25 1.5	950	1900	2.6	1.5 4.3
LEXINGTON CR L4	50 50 117 37	15	.55	.53	450	1700 .45	2.5	25 58	1780	3100	1.9	1.1 3.1
LITTLE GLACIER CR L8	50 26 116 55	36	1.3	.50	60	600 .72	0.0	25 26	550	1900	3.8	1.7 8.7
LOFTUS CR L1	50 56 118 49	17	.75	.45	250	1000 .51	0.0	25 0.5	1350	2000	1.8	1.1 3.1
LOKI CR L11	49 50 116 51	28	.87	.45	430	2400 .57	2.5	25 14	2600	5400	2.6	1.3 4.9
LOST LEDGE CR L9	50 06 116 56	14	.28	.47	430	1700 .36	0.0	25 0.5	860	1900	2.6	1.0 6.6

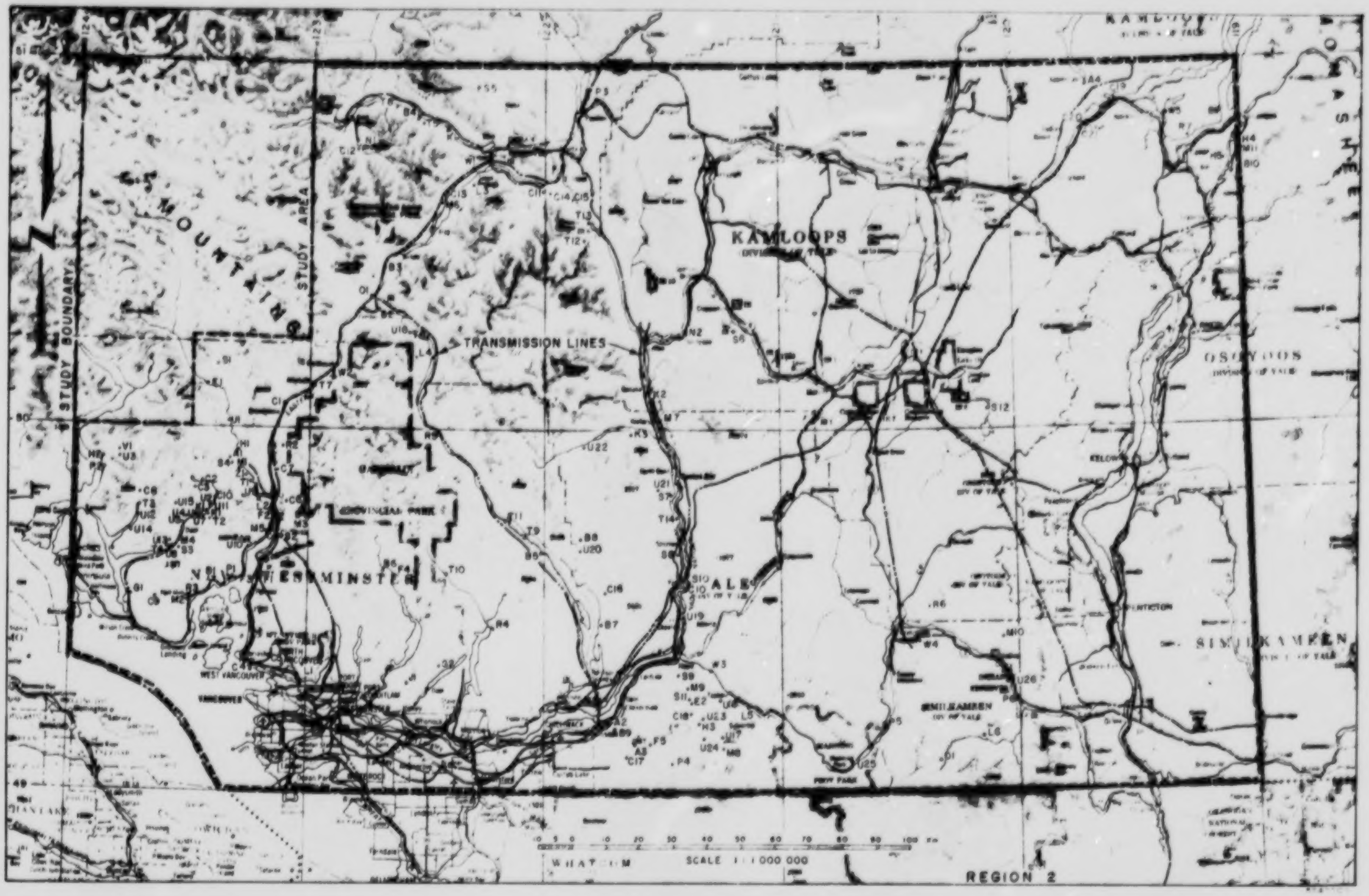
BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
LUXOR CR L10	50 46 116 10	81	.97	.52	100	1400 .70	3.0	25 3.0	700	3400	5.3	2.0 14
MABEL CR M2	50 37 118 36	10	.22	.47	250	800 .36	6.0	25 11	420	1800	5.2	2.2 12
McDONALD CR M7	50 34 116 25	50	1.8	.52	250	1100 .71	2.0	25 36	3100	3500	1.2	0.5 3.0
McDOUGAL CR M4	50 58 117 37	85	3.4	.53	150	850 .95	16	25 80	3600	6400	1.9	1.1 3.2
MEADOW CR M5	50 18 117 03	23	.62	.47	180	1300 .52	0.0	25 4.0	800	2100	3.1	2.1 4.8
MENHINICK CR M3	50 49 117 39	17	.60	.53	200	900 .47	0.5	25 53	860	1900	2.3	1.3 3.9
MIDGE CR M8	49 22 116 52	243	5.6	.55	30	1000 1.6	6.5	25 33	1200	7700	6.4	3.5 12
MITCHELL R FALLS M9	50 48 115 42	74	1.8	.50	N/A	N/A N/A	23	25 45	N/A	N/A	N/A	N/A N/A
MITCHELL R RAPIDS M10	50 47 115 41	110	2.6	.50	N/A	N/A N/A	20	25 40	N/A	N/A	N/A	N/A N/A
MULVEHILL CR M1	50 51 118 07	42	1.9	.45	150	550 .70	0.0	25 17	2000	2100	1.3	0.7 2.6
MURPHY CR M6	49 10 117 44	73	.95	.40	60	500 .63	0.6	25 2.5	410	1400	4.9	2.7 9.0
NEMO CR N1	49 55 117 25	68	2.0	.45	490	3300 .81	3.5	25 3.0	7100	15500	2.7	1.4 5.3
NEXT CR N2	49 18 116 45	155	3.6	.55	120	1100 1.1	1.0	25 25	3000	4900	1.7	0.9 3.0
OCTOPUS CR O2	49 45 118 06	45	.68	.40	150	650 .49	1.0	138 6.0	730	1700	3.2	1.7 6.1
OUTLET CR O1	50 20 118 30	40	.60	.45	150	1400 .54	1.5	25 3.0	640	2400	5.0	2.4 9.2

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
PALLISER FALLS #1 P5	50 32 115 36	277	6.7	.50	N/A	N/A N/A	2.0	25 53	N/A	N/A	N/A	N/A N/A
PALLISER FALLS #2 P6	50 32 115 28	358	8.6	.50	N/A	N/A N/A	8.0	25 63	N/A	N/A	N/A	N/A N/A
PAYNE CR P2	50 37 117 51	54	1.6	.53	100	400 .67	0.0	25 45	1100	1800	1.6	0.9 2.9
POOL CR P1	50 47 117 38	65	2.5	.53	350	3000 .91	0.0	25 51	6200	12300	2.1	1.3 3.5
POPLAR CR P3	50 26 117 08	128	4.2	.47	120	2700 1.3	0.0	25 17	3600	12000	4.0	2.5 6.3
POWDER CR P4	49 53 116 51	45	1.4	.45	370	2500 .70	2.0	25 23	3600	7300	2.5	1.3 4.8
QUARRIE CR Q1	50 16 114 59	59	1.2	.50	50	550 .72	1.0	25 12	420	1900	5.1	2.9 8.9
RAPID CR R2	50 27 117 10	35	1.2	.47	300	2400 .67	0.0	25 21	2500	5200	2.5	1.6 3.9
RIOULX CR R1	50 17 118 05	53	.90	.45	200	2000 .64	6.0	25 30	1290	4500	4.4	1.8 11
SANCA CR S13	49 23 116 43	100	2.3	.55	120	1000 .88	3.0	25 25	2000	4000	2.1	1.1 3.9
SCHROEDER CR S11	50 02 116 53	32	.64	.47	300	2300 .53	0.0	25 0.5	1400	3400	3.0	1.2 7.7
SEPTET CR S10	50 48 116 41	40	1.4	.52	150	950 .69	2.0	25 34	1500	2810	2.0	0.7 6.3
SHANNON CR S9	50 05 117 29	33	1.5	.47	180	1700 .76	0.0	25 2.0	1900	3800	2.3	1.4 3.9
SHAW CR S14	49 15 116 43	48	1.1	.55	240	1000 .59	1.0	25 21	1900	2500	1.3	0.7 2.5
SHUSWAP R BRENDA F S1	50 21 118 32	N/A	39	.45	N/A	N/A N/A	0.0	25 0.0	N/A	N/A	N/A	N/A N/A

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
SICAMOUS CR S6	50 48 118 58	64	1.6	.45	200	1400 .74	0.0	25 0.0	2300	3300	1.8	0.5 6.2
SKOOKUMCHUCK F #2 S16	49 58 116 08	133	2.4	.40	N/A	N/A N/A	1.0	25 42	N/A	N/A	N/A	N/A N/A
SKOOKUMCHUCK F #1 S15	49 58 116 07	141	2.5	.40	N/A	N/A N/A	1.0	25 41	N/A	N/A	N/A	N/A N/A
SLEWISKIN CR S8	50 08 117 47	76	3.4	.45	60	1200 1.2	0.0	25 2.0	1500	5400	4.6	2.7 7.7
SMYTH CR S3	50 32 118 43	16	.29	.45	600	2000 .36	0.0	25 15	1200	2600	2.6	0.9 7.6
SOUTH CRANBERRY CR S4	50 46 118 06	59	2.7	.52	200	900 .83	3.0	25 29	3800	4100	1.1	0.6 2.2
SOWSAP CR S2	50 26 118 46	52	.42	.45	200	2100 .49	3.0	25 3.5	600	3100	6.4	1.8 23
SPECTRUM CR FALLS S5	50 29 118 27	78	2.0	.50	N/A	N/A N/A	0.2	25 18	N/A	N/A	N/A	N/A N/A
STEWART CR S7	49 07 118 15	18	.19	.40	250	1050 .31	6.0	25 8.0	340	1700	6.8	2.8 16
STOCKDALE CR S12	50 35 116 35	66	2.6	.52	50	700 1.0	9.0	25 38	950	4500	5.2	2.0 13
TAM O'SHANTER CR T5	49 48 116 51	31	.96	.45	490	3000 .60	3.5	25 10	3400	7800	2.9	1.5 5.6
TEMPLETON CR T4	50 48 116 29	29	1.0	.52	250	1700 .62	4.0	25 21	1800	3900	2.3	0.7 7.1
TENDERFOOT CR T3	50 28 117 13	45	1.5	.47	240	2500 .78	0.0	25 28	2600	6100	2.8	1.7 4.9
TOWN CR T2	50 46 117 45	14	.49	.53	400	1400 .44	2.0	25 44	1450	2600	1.9	1.1 3.2
TSUIUS CR T1	50 37 118 40	208	5.0	.47	150	1650 1.2	4.0	25 7.0	5300	8600	1.9	0.9 4.3

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
UNNAMED CR U10	50 21 116 51	16	.32	.55	430	2000 .41	0.5	25 15	1000	2400	2.4	1.3 4.6
UNNAMED CR U2	50 55 118 07	19	.85	.45	250	1150 .54	0.5	25 1.0	1500	2300	1.9	1.0 3.7
UNNAMED CR U13	49 59 116 03	39.5	.75	.40	300	1100 .50	1.5	25 37	1600	2500	2.2	1.0 4.9
UNNAMED CR U8	50 09 116 38	23	.46	.50	240	1000 .44	4.5	25 21	820	2300	3.1	1.7 5.9
UNNAMED CR U11	50 21 116 48	15	.30	.50	240	900 .36	0.5	25 19	530	1330	2.9	1.5 5.3
UNNAMED CR U12	49 59 116 00	8.2	.16	.40	560	1550 .31	2.0	25 33	660	1930	4.2	1.8 9.3
UNNAMED CR U6	50 20 116 51	14	.28	.50	300	1150 .36	0.5	25 14	620	1500	2.6	1.4 4.8
UNNAMED CR U9	50 06 116 46	9	.18	.50	550	1650 .31	0.0	25 8.0	730	1600	2.5	1.4 4.5
UNNAMED CR U4	50 58 118 36	10	.50	.45	300	700 .40	0.0	25 7.0	1100	1400	1.6	0.8 2.9
UNNAMED CR FALLS U1	50 58 118 36	11	.55	.45	N/A	N/A N/A	0.0	25 7.0	N/A	N/A	N/A	N/A N/A
UNNAMED CR U7	50 59 116 45	24	.72	.52	400	1100 .47	2.0	25 34	2000	2600	1.4	0.7 2.7
UNNAMED CR U3	50 57 118 24	24	1.2	.45	300	1100 .59	0.0	25 6.0	2500	2600	1.3	0.7 2.4
UNNAMED CR U5	50 07 116 44	11	.22	.50	490	1400 .30	0.5	25 13	770	1500	2.1	1.1 4.0
VAN HOUTEN CR V2	49 40 118 07	38	.57	.40	150	700 .47	4.0	138 16	600	2000	4.5	2.4 8.6
VICTOR CR V1	50 57 118 24	10	.50	.45	300	550 .40	0.0	25 6.0	1100	1300	1.5	0.8 2.7

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
VOWELL CR V3	50 53 116 52	132	5.9	.52	50	800 1.4	6.0	25 50	2100	6600	3.4	1.4 7.9
WAP CR FALLS W1	50 54 118 29	66	3.3	.45	N/A	N/A N/A	0.5	25 14	N/A	N/A	N/A	N/A N/A
WARREN CR W6	50 58 116 42	47	1.4	.52	550	3400 .69	6.0	25 30	5500	12700	2.5	1.3 4.8
WEE SANDY CR W4	50 00 117 25	59	1.8	.47	180	900 .72	0.0	25 10	2300	2900	1.5	0.8 2.8
WHATSHAN L DAM & F W2	49 54 118 07	590	7.0	.40	N/A	N/A N/A	0.6	60 1.0	N/A	N/A	N/A	N/A N/A
WILSON CR FALLS W3	50 08 117 20	205	9.2	.47	60	550 1.5	1.0	25 11	3900	5500	1.7	1.0 2.8
WILSON CR W8	49 35 116 52	25	.58	.55	609	2700 .47	3.0	25 12	2500	6000	2.5	1.1 5.4
WOODBURY CR W7	49 48 116 57	83	1.9	.55	300	3900 .90	0.0	25 6.0	4190	13900	3.4	1.6 7.6
WRAGGE CR W5	50 04 117 28	25	1.1	.45	244	1800 .66	2.0	25 2.0	1990	3700	2.4	1.4 4.0
YARD CR FALLS Y2	50 53 118 48	122	3.1	.45	N/A	N/A N/A	1.0	25 2.0	N/A	N/A	N/A	N/A N/A
YARD CR Y1	50 54 118 48	122	3.1	.45	150	1550 1.0	0.0	25 0.0	3290	5700	2.2	0.7 7.4


STUDY BOUNDARY
STUDY AREA
MOUNTAINS
TRANSMISSION LINES
KAMLOOPS
OSOYOOS
SIMILKAMEEN
WESTMINSTER
WEST VANCOUVER
VANCOUVER
KELOWNA
PENTICTON
PROVINCIAL PARK
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REGION 2

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
ADAMS R RAPIDS A4	50 56 119 39	N/A	71	.60	N/A	N/A N/A	0.0	25 0.0	N/A	N/A	N/A	N/A N/A
AIRPLANE CR A3	49 08 121 37	16	.90	.63	300	1400 .56	2.5	25 7.0	2000	2800	1.3	0.8 2.1
ANDERSON CR A2	49 11 121 43	4	.21	.63	850	1500 .31	3.0	25 5.0	1300	2700	1.8	1.1 3.0
ASHLU CR A1	49 55 123 20	310	23	.55	120	1400 2.2	2.0	230 5.0	20500	20000	1.0	0.6 1.7
BASTION CR B11	50 51 119 05	12	.24	.45	300	1000 .36	0.0	25 17	500	1200	2.8	1.1 7.3
BEAR CR B7	49 28 121 46	29	1.6	.60	365	2100 .71	0.0	25 20	4100	6200	1.4	0.8 2.5
BIG SILVER CR B8	49 42 121 51	295	13	.55	100	1600 1.9	0.0	25 0.0	9500	15000	1.6	0.7 3.9
BIRKENHEAD R #1 B2	50 20 122 43	590	23	.63	30	200 2.0	1.0	25 1.0	5100	7000	1.2	0.8 1.8
BIRKENHEAD R #2 B3	50 27 122 41	380	15	.63	61	750 2.0	2.0	25 2.0	6700	9000	1.2	0.8 1.8
BLURTON CR B10	50 41 119 02	19	.48	.45	400	1600 .44	1.0	25 1.0	1400	2400	2.1	1.3 3.5
BOBB CR B4	50 51 122 33	40	.80	.52	300	1400 .53	10	60 22	1700	4100	2.6	1.2 5.6
BOISE CR B6	49 37 122 41	59	4.7	.55	275	2200 1.1	5.0	25 50	9300	14300	1.6	0.8 3.4
BOX CANYON CR B1	49 35 123 24	6	.76	.55	400	1400 .50	2.0	138 2.0	2100	3000	1.4	0.9 2.2
BREMNER CR B5	49 40 122 01	39	3.1	.55	60	200 .83	0.5	25 7.0	1400	2300	1.8	0.8 3.7
BRIDAL CR @ FALLS B9	49 10 121 42	3	.16	.63	N/A	N/A N/A	1.0	25 4.0	N/A	N/A	N/A	N/A N/A

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
CADWALLADER CR C12	50 46 122 48	172	4.8	.52	50	600 1.2	2.0	25 0.5	1700	4400	2.8	1.0 7.8
CALLAGHAN CR C1	50 04 123 06	200	16	.60	60	1400 2.2	1.0	230 2.0	7000	15200	2.1	1.2 3.5
CANTELON / YOLA CR C18	49 13 121 23	66	3.0	.63	105	2000 1.1	2.0	25 22	2200	8000	3.2	1.9 5.4
CAPILANO R DAM C5	49 21 123 06	190	N/A	.55	100	N/A N/A	0.0	25 0.0	N/A	N/A	N/A	N/A N/A
CAYOOSH CR #1 C11	50 39 122 01	835	20	.53	50	900 2.3	3.0	25 7.0	7000	13200	2.0	1.3 3.0
CAYOOSH CR FALLS C14	50 39 121 59	887	21	.53	N/A	N/A N/A	1.0	25 4.0	N/A	N/A	N/A	N/A N/A
CAYOOSH CR #2 C15	50 39 121 59	887	21	.53	30	800 2.5	1.0	25 4.0	4620	12000	2.8	1.9 4.2
CHAPMAN CR FALLS C9	49 32 123 38	33	2.4	.55	N/A	N/A N/A	1.0	25 11	N/A	N/A	N/A	N/A N/A
CHASE CR C20	50 49 119 41	20	.99	.45	100	500 .58	0.0	25 0.0	700	1400	2.5	1.0 5.9
CHEEKYE R C6	49 48 123 06	24	1.7	.55	120	1200 .81	4.0	25 7.0	1400	3900	2.7	1.7 4.2
CHICKWAT CR C8	49 49 123 43	46	3.7	.55	180	1050 .98	2.0	25 27	4800	5500	1.2	0.7 1.9
CHIPMUNK CR C17	49 06 121 39	37	2.0	.63	455	3000 .80	2.0	25 3.0	6500	10800	1.5	0.9 2.4
CLOWHOM R C2	49 51 123 27	48	3.6	.55	120	1000 1.0	12	138 25	3100	6600	2.2	1.3 3.5
CLOWHOM R C3	49 50 123 29	22	1.7	.55	320	600 .60	14	138 27	3800	4800	1.3	0.8 2.1
CLOWHOM R C10	49 49 123 23	104	7.8	.55	60	400 1.3	6.0	138 19	3400	5500	1.7	1.0 2.8

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
COGBURN CR C16	49 33 121 45	130	5.9	.60	100	1050 1.3	0.0	25 35	4200	6500	1.5	0.6 3.5
CONNEL CR C13	50 39 122 25	50	.65	.52	950	3800 .48	5.0	60 0.5	4400	12700	3.1	1.5 6.6
CORNING CR C19	50 54 119 32	26	.52	.45	100	700 .49	0.0	25 0.0	370	1300	4.3	1.6 11
CULLITON CR C7	49 53 123 09	35	2.6	.55	370	3500 .94	2.0	25 15	6800	14000	2.1	1.4 3.3
CYPRESS CR C4	49 20 123 14	13	1.3	.55	105	825 .70	0.0	25 0.0	1000	1800	1.9	1.1 3.2
DURUISSEAU CR D1	49 05 120 21	36	.29	.45	250	1600 .41	2.0	25 24	540	2100	5.0	2.5 10
EATON CR E2	49 15 121 23	7	.30	.63	850	2150 .36	3.0	25 16	1900	4300	2.0	1.2 3.5
ELAHO CR E1	50 07 123 26	1200	108	.60	30	650 4.2	1.0	230 27	19400	30000	1.5	0.9 2.5
FISH HATCHERY CR F4	49 36 122 38	13.5	1.1	.55	670	1600 .53	3.0	25 50	5200	6600	1.3	0.6 2.8
FOLEY CR F5	49 08 121 33	17	.85	.60	240	2800 .64	4.0	25 14	1500	4900	3.1	1.9 5.3
FRIES CR F2	49 45 123 09	23	1.6	.55	180	1100 .72	4.0	25 3.0	2000	3200	1.6	1.0 2.6
FURRY CR FALLS F1	49 35 123 12	38	2.6	.57	N/A	N/A N/A	2.0	25 6.0	N/A	N/A	N/A	N/A N/A
FURRY CR F3	49 35 123 13	52	3.6	.57	230	1600 1.0	2.0	25 6.0	5800	6200	1.1	0.6 1.8
GOLD CR G2	49 21 122 27	75	5.3	.55	50	250 1.1	3.0	25 16	1900	3100	1.7	0.6 4.5
GRAY CR G1	49 32 123 45	52	3.6	.55	95	700 1.0	2.0	25 8.0	2490	4000	1.7	1.0 2.8

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
HICKS CR H3	49 11 121 21	18	.81	.63	120	900 .58	2.0	25 25	700	2200	2.8	1.7 4.6
HIGH CR H2	49 55 123 52	31	2.2	.55	210	1000 .77	2.0	25 21	3300	3710	1.2	0.6 2.1
HIGH FALLS CR H1	49 56 123 18	27	2.0	.55	520	1700 .71	3.0	230 1.0	7500	7700	1.1	0.6 1.7
HILLS CR H5	50 43 119 04	34	.68	.45	250	1250 .51	1.0	25 3.0	1200	2300	2.3	0.9 6.1
HUMMING BIRD CR H4	50 46 119 00	15	.30	.45	250	750 .36	0.0	25 1.0	550	1100	2.5	1.4 4.4
JOFFRE CR J1	49 18 122 35	95	3.8	.57	190	900 .96	1.0	25 10	5200	4800	0.9	0.5 1.6
KEARY CR K1	50 49 122 25	41	.60	.52	400	2800 .52	10	60 12	1700	6000	3.7	1.5 9.0
KOOKIPI CR K3	49 59 121 38	116	4.6	.47	350	2700 1.1	7.0	25 12	11600	20000	2.0	0.8 5.4
KWOIEK CR K2	50 07 121 35	247	7.4	.60	350	3500 1.4	6.0	25 7.0	18600	35000	1.8	0.9 3.5
LAFORGUE CR L5	49 14 121 09	14	.62	.60	300	1200 .47	2.0	25 27	1300	2200	1.6	0.9 2.7
LAKE LOVELY WATER L2	49 48 123 13	10	.75	.60	1100	3400 .48	7.0	25 9.0	5900	12400	2.0	1.2 3.2
LAKEVIEW CR L6	49 09 120 10	40	.32	.45	550	2900 .41	4.0	25 20	1300	4300	4.1	2.2 7.8
LIZZIE CR L4	50 12 122 28	70	3.5	.57	230	2000 1.0	3.0	138 1.0	5700	9400	1.6	0.9 3.0
LOST VALLEY CR L3	50 40 122 18	94	.94	.52	350	1050 .52	2.0	60 6.0	2300	2900	1.3	0.7 2.5
LYNN CR L1	49 21 123 01	40	4.0	.55	75	1800 1.3	0.0	25 0.0	2100	6400	3.1	1.9 5.0

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
MAIMEN CR M9	49 17 121 24	9	.39	.60	610	3150 .44	4.0	25 11	1700	5400	2.9	1.7 5.0
MAMQUAM CR M3	49 43 123 04	258	22	.57	190	825 1.8	2.0	25 6.0	28700	14100	0.8	0.6 1.5
MARA CR M11	50 46 119 00	23	.46	.45	250	1000 .44	0.0	25 1.0	850	1600	2.4	1.4 4.3
MASELPANIK CR M8	49 07 121 15	52	2.3	.63	300	2500 .88	3.0	25 37	5100	9400	1.7	1.0 2.8
MAWBY CR M1	49 53 123 18	9	.65	.55	580	1150 .44	5.0	230 2.0	2700	3600	1.3	0.8 2.2
McGILLIVARY CR M6	50 37 122 26	77	1.2	.52	350	1300 .59	2.0	60 1.0	2900	3800	1.4	0.6 3.5
McNAIR CR M2	49 31 123 30	18	2.1	.55	180	1600 .86	2.0	25 1.0	2800	5200	1.9	1.2 3.1
McNULTY CR M10	49 25 120 05	200	1.3	.40	250	1900 .69	2.5	25 10	2200	4100	2.6	1.3 5.1
MISERY CR FALLS M4	49 40 123 35	60	4.8	.55	N/A	N/A N/A	1.0	138 6.0	N/A	N/A	N/A	N/A N/A
MONMOUTH CR M5	49 43 123 11	8	.59	.55	470	1000 .44	5.0	25 3.0	2040	2800	1.4	0.8 2.3
MOWHOKAM CR M7	50 02 121 31	118	1.4	.50	100	1000 .76	3.0	25 3.0	1000	3100	3.4	1.5 7.7
NICOAMEN CR N2	50 16 121 24	153	1.5	.50	200	600 .63	2.0	25 10	2200	2400	1.2	0.5 3.1
NOEL CR N1	50 46 122 48	98	3.2	.52	50	400 .99	3.0	60 2.0	1160	3100	2.9	1.2 6.9
OWL CR O1	50 22 122 44	55	2.2	.62	150	900 .81	3.0	25 1.0	2400	3900	1.5	1.0 2.3
PAUL CR P6	49 15 120 01	106	.67	.40	120	400 .47	5.0	25 1.0	570	1800	4.3	2.3 8.2

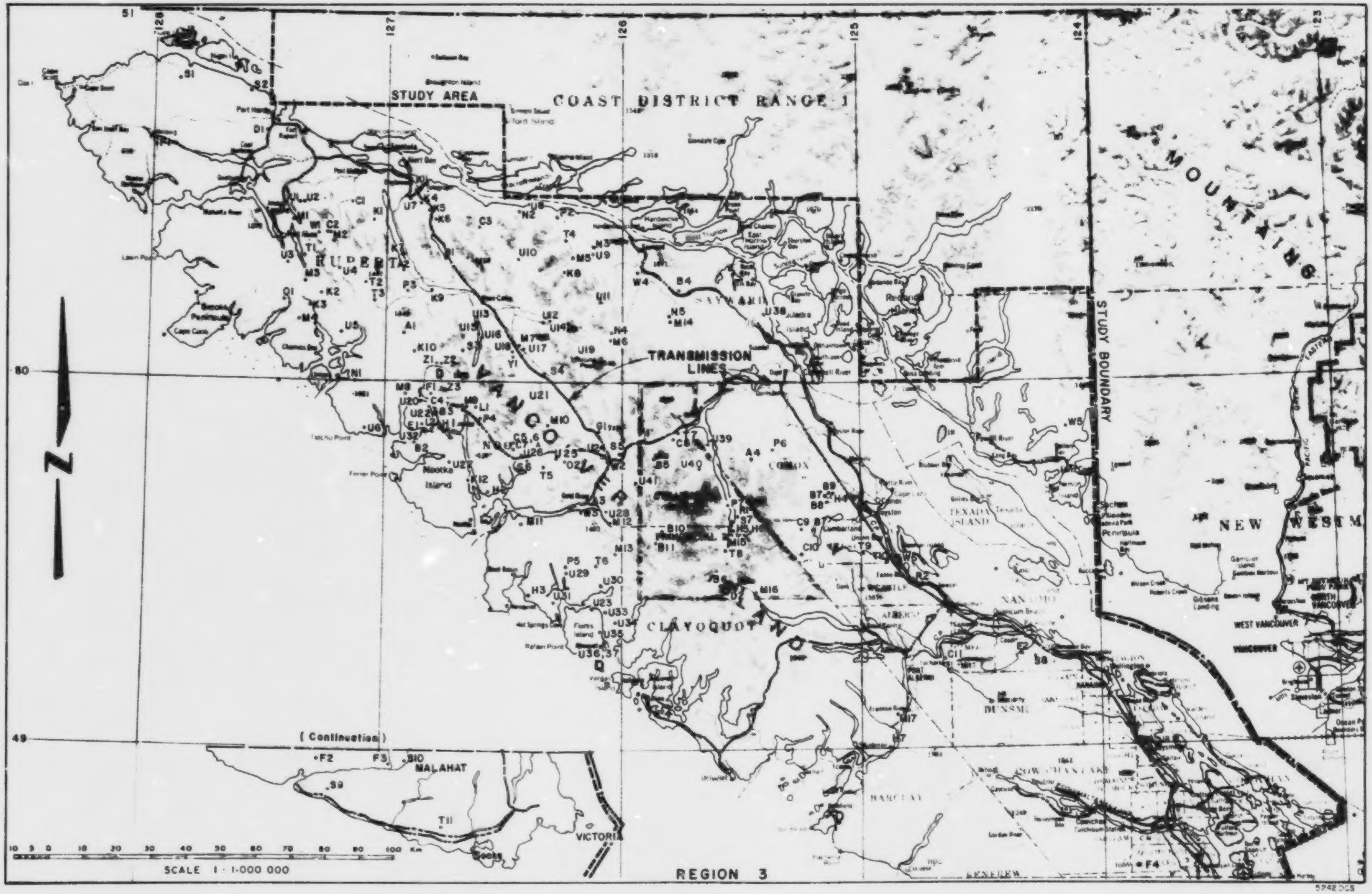
BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
PAVILION CR P3	50 54 121 46	38	.15	.50	350	2350 .36	3.0	60 0.0	400	2200	6.2	3.4 11
PERKETTS CR P2	49 53 123 52	27	1.9	.55	340	1000 .68	1.0	25 15	4500	4200	1.0	0.5 1.8
PLACER CR P5	49 11 120 34	69	.69	.45	250	1900 .55	2.0	25 25	1200	3200	3.2	1.4 7.5
POST CR P4	49 05 121 28	22	1.1	.60	125	500 .59	1.5	25 17	1020	1800	1.7	1.0 2.8
POTLATCH CR P1	49 35 123 19	4	.43	.55	150	1300 .47	2.0	138 1.0	470	2100	4.6	2.8 7.5
RAINY R R3	49 32 123 30	56	7.0	.55	60	800 1.5	3.0	25 3.0	3070	6200	2.1	1.4 3.1
RED CR R6	49 31 120 23	110	.28	.40	260	1250 .41	5.0	25 4.0	540	2100	5.4	2.4 12
RED TUSK CR R1	49 47 123 25	32	2.6	.55	180	1400 .90	3.0	138 13	3300	5800	1.8	1.1 2.9
REINECKER CR R7	50 47 119 13	48	.96	.45	100	500 .58	0.0	25 4.0	690	1400	2.6	1.0 7.0
ROARING CR R4	49 27 122 13	20	1.4	.55	200	900 .65	1.0	25 25	2000	2700	1.4	0.5 3.7
ROGERS CR R5	49 59 122 27	148	10	.57	120	1200 1.6	5.0	138 1.0	9100	11300	1.2	0.8 1.8
RUBBLE CR R2	49 57 123 07	56	2.8	.60	730	3000 .83	5.0	25 4.0	14700	19600	1.3	0.5 3.3
SCUZZZY CR S7	49 49 121 28	226	7.9	.47	70	1100 1.6	2.0	25 3.0	3900	8500	2.6	0.8 8.1
SECHELT CR S3	49 40 123 33	75	6.0	.55	153	1200 1.3	2.0	138 0.5	6600	7200	1.1	0.7 1.7
SHAKAN CR S6	50 16 121 12	86	.86	.43	50	200 .53	2.0	25 2.0	300	1300	4.6	1.7 12

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
SHULAPS CR S5	50 56 122 17	58	.58	.52	200	1550 .52	5.0	60 30	830	3200	4.2	2.2 7.8
SIGURD CR FALLS S4	49 54 123 20	22	1.7	.55	N/A	N/A N/A	3.0	230 6.0	N/A	N/A	N/A	N/A N/A
SIWASH CR S10	49 34 121 24	66	3.0	.50	200	600 .81	15	25 12	4200	5700	1.5	0.6 3.7
SOWERBY CR S9	49 19 121 26	30	1.4	.63	425	3400 .71	3.0	25 7.0	4100	9800	2.1	1.2 3.6
SPAHOMIN CR @ RAP S12	50 03 120 06	N/A	.67	.50	N/A	N/A N/A	6.0	25 14	N/A	N/A	N/A	N/A N/A
SPUZZUM CR S8	49 39 121 26	213	7.5	.60	50	500 1.4	2.0	25 2.0	2600	5100	1.8	0.3 9.7
SQUAMISH R S1	50 10 123 24	290	26	.60	60	1400 2.6	2.0	230 30	11400	22400	1.9	1.1 3.1
STAWAMUS CR S2	49 42 123 07	33	2.8	.55	274	2650 .97	0.0	25 3.0	5500	9400	1.8	1.1 2.7
SWANEE CR S11	49 15 121 23	5	.23	.60	460	1900 .36	2.0	25 17	770	2100	2.5	1.5 4.3
TANTALUS CR T1	49 51 123 15	12	.90	.55	762	3000 .45	5.0	230 2.0	4900	9200	1.9	1.2 3.2
TAQUAT CR T2	49 45 123 25	38	3.1	.55	305	1400 .88	2.0	138 11	6700	7100	1.1	0.7 1.7
TEXAS CR T13	50 34 121 49	170	2.6	.50	150	900 .86	0.5	25 18	2700	3600	1.5	0.6 3.8
TEXAS CR T12	50 31 121 50	153	2.3	.50	100	800 .87	5.0	25 23	1600	3800	2.6	1.0 6.6
THOMAS LAKE T10	49 36 122 25	14	1.1	.60	520	1700 .57	0.5	69 50	4100	5500	1.2	0.6 2.6
THORNHILL CR T4	49 40 123 36	15	1.2	.55	459	1250 .57	2.0	138 0.0	3970	4220	1.1	0.7 1.8

C SMALL HYDRO SSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢kWh	COST RANGE
TIPELLA CR T11	49 45 122 10	61	4.9	.55	90	300 .99	1.5	360 0.0	3200	3600	1.2	0.6 2.4
TOMMY CR T5	50 50 122 31	68	1.2	.52	300	1800 .64	0.0	60 20	2500	4140	1.8	0.8 4.4
TRETHEWAY CR T9	49 42 122 05	94	7.5	.55	30	150 1.3	0.5	360 0.0	1600	3500	2.2	1.1 4.6
TRUAX CR T8	50 53 122 38	50	1.0	.52	200	700 .55	0.0	60 18	1400	2040	1.6	0.7 3.3
TSILEUH CR T14	49 46 121 26	29	.87	.47	700	3900 .57	0.0	25 5.0	4300	11500	3.2	0.8 13
TWENTYONE MILE CR T7	50 07 122 59	28	2.2	.60	185	1000 .80	3.0	25 1.5	2900	3600	1.2	0.7 2.0
TWIN ONE CR T6	50 15 122 30	57	2.3	.56	430	4100 .90	5.0	138 1.0	6900	19500	2.8	1.6 4.9
TZOONIE CR T3	49 47 123 43	159	11	.55	30	320 1.7	0.5	25 23	2400	5230	2.3	1.2 4.1
UNNAMED CR U4	49 45 123 31	69	5.5	.55	122	350 1.0	0.0	138 6.0	4800	3770	0.8	0.5 1.3
UNNAMED CR U5	49 44 123 32	5.5	.44	.55	397	700 .41	1.0	138 5.0	1300	1730	1.4	0.8 2.2
UNNAMED CR U3	49 55 123 46	13	.88	.55	579	3000 .56	0.0	25 25	3650	8070	2.3	1.3 4.2
UNNAMED CR U23	49 12 121 20	5.8	.26	.63	670	2050 .36	4.0	25 24	1300	3400	2.4	1.4 4.0
UNNAMED CR U18	49 15 121 15	21	.93	.60	180	1300 .61	2.0	25 25	1200	2900	2.2	1.3 3.9
UNNAMED CR U26	49 18 120 04	13	.08	.40	600	1300 .20	2.0	25 1.0	340	1100	4.5	2.4 8.7
UNNAMED CR U10	49 41 123 16	4.1	.41	.55	580	1700 .41	4.0	25 2.5	1770	3400	2.0	1.2 3.2

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
UNNAMED CR U15	49 47 123 34	19	1.4	.55	457	1200 .60	10	138 17	4600	5900	1.3	0.8 2.2
UNNAMED CR U17	49 09 121 15	20	.90	.63	245	1500 .59	3.0	25 30	1570	3500	2.0	1.2 3.4
UNNAMED CR U2	49 49 123 23	4.7	.38	.55	793	1150 .36	2.0	138 17	2200	3300	1.6	1.0 2.5
UNNAMED CR U14	49 43 123 45	13	1.0	.55	427	1200 .54	2.0	25 17	3200	3800	1.2	0.8 2.0
UNNAMED CR U11	49 48 123 24	9.4	0.8	.55	793	2700 .49	6.0	138 15	4280	9100	2.2	1.4 3.6
UNNAMED CR U20	49 40 121 51	13	.65	.60	540	2000 .47	4.0	25 55	2500	4800	1.8	0.8 4.0
UNNAMED CR U22	49 57 121 50	58	2.3	.47	250	1500 .83	5.0	25 28	5800	9600	1.8	0.7 4.7
UNNAMED CR U25	49 05 120 43	9	.18	.50	150	825 .36	2.0	25 11	200	1250	6.9	3.4 13
UNNAMED CR U24	49 09 121 20	26	1.2	.63	243	2100 .69	5.0	25 30	2000	5000	2.2	1.3 3.7
UNNAMED CR U6	49 46 123 26	7.8	.62	.55	458	1100 .45	2.0	138 14	2090	2700	1.3	0.8 2.1
UNNAMED CR U7	49 45 123 27	11	.88	.55	550	1100 .48	2.0	138 11	3500	3700	1.1	0.7 1.8
UNNAMED CR U21	49 50 121 31	58	2.0	.47	300	2200 .82	3.0	25 9.0	4300	7700	2.1	0.7 6.7
UNNAMED CR U12	49 45 123 43	19	1.5	.55	214	600 .62	1.0	25 18	2340	2500	1.1	0.7 1.8
UNNAMED CR U1	50 01 123 21	22	1.8	.60	275	700 .64	8.0	230 15	3500	3900	1.1	0.6 1.8
UNNAMED CR U19	49 29 121 25	11	.45	.60	425	2600 .45	5.0	25 3.0	1300	3800	2.6	1.5 4.7

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
UNNAMED CR U13	49 41 123 35	2.3	.18	.57	793	1800 .31	3.0	138 0.0	1100	2860	2.6	1.6 4.2
UNNAMED CR FALLS U9	49 50 123 14	14	1.1	.55	N/A	N/A N/A	4.0	25 8.0	N/A	N/A	N/A	N/A N/A
UNNAMED CR U8	49 40 123 35	1.9	.15	.60	1037	2400 .25	3.0	138 0.0	1140	3300	2.8	1.7 4.6
URE CR U16	50 16 122 35	119	6.0	.57	275	2050 1.2	15	25 10	11800	16500	1.4	0.8 2.6
VANCOUVER R V1	49 56 123 48	115	8.1	.55	60	900 1.6	2.5	25 25	3500	7800	2.3	1.2 4.1
WEDGE CR W2	50 10 122 54	51	3.6	.60	215	1500 1.0	3.0	25 2.0	5500	6500	1.1	0.6 2.0
WHITE CR W5	50 51 119 19	60	.60	.60	50	300 .50	0.0	25 0.0	210	900	3.9	1.5 10
WHITECAP CR W1	50 43 122 18	73	.73	.52	200	950 .52	2.0	60 1.0	1050	2220	2.3	1.3 4.3
WILLIS CR W4	49 25 120 25	120	.60	.45	150	1200 .53	4.0	25 9.0	640	2400	4.6	2.7 7.9
WRAY CR W3	49 20 121 18	18	.83	.60	305	2000 .57	3.0	25 12	1800	3600	1.9	1.1 3.2
ZENITH CR Z1	49 52 123 16	1.5	.11	.60	1159	2800 .25	5.0	25 15	980	3800	3.7	2.2 6.2


COAST DISTRICT RANGE 1
STUDY AREA
STUDY BOUNDARY
MOUNTAINS
NEW WESTM
TRANSMISSION LINES
RUPERT
SAYWARD
COMOX
NANAIMO
CLAYOQUOT
ALBERNI
DUNSMUIR
COWICHAN LAKE
BARCLAY
RENFREW
TEXADA ISLAND
Nootka Island
WEST VANCOUVER
VANCOUVER
NORTH VANCOUVER
VICTORIA
MALAHAT
Sooke
Port Hardy
(Continuation)
N
51
50
49
128
127
126
125
124
123
SCALE 1 : 1 000 000
10 5 0 10 20 30 40 50 60 70 80 90 100 Km
5242 DCS

REGION 3

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
ADRIAN CR A4	49 48 125 27	26	1.8	.65	50	625 .87	0.0	25 0.0	650	2500	3.3	1.8 6.0
AHAMINGUS CR A3	49 41 126 07	10	.99	.65	40	100 .52	0.8	25 0.5	280	1200	3.5	2.1 5.7
ARTLISH R A1	50 08 126 55	49	5.9	.65	30	600 1.5	6.0	138 30	1300	6000	4.0	2.6 6.3
ATLUCK CR A2	50 18 126 56	72	8.6	.65	30	700 1.7	1.0	138 16	1900	7000	3.2	2.1 5.1
BANCROFT CR B11	49 34 125 52	29	2.2	.65	100	560 0.8	15	138 26	1500	4700	2.6	1.5 4.6
BARR CR B3	49 55 126 47	25	3.5	.65	30	400 1.1	6.0	25 10	760	3800	4.3	2.8 6.7
BEDWELL R B6	49 27 125 36	25	3.1	.62	50	500 1.0	0.0	138 32	1100	3000	2.5	1.6 3.9
BEECH CR B7	49 36 125 12	19	1.3	.65	50	125 .57	0.0	25 8.2	460	1100	1.9	1.2 3.0
BIG TREE CR B4	50 15 125 45	35	1.7	.67	100	1900 .92	1.5	25 1.5	1250	6000	4.1	2.3 7.4
BONANZA R B1	50 20 126 44	68	4.4	.68	60	1400 1.4	1.0	138 0.8	1900	7800	3.4	2.2 5.3
BRODRICK CR B2	49 50 126 53	9	1.4	.65	120	1650 .79	3.0	25 21	1100	4500	3.3	2.2 5.2
BROWNS R #1 B8	49 41 125 09	75	5.9	.65	50	400 1.2	0.3	25 2.1	2100	3400	1.4	1.0 2.1
BROWNS R #2 B9	49 42 125 08	82	6.4	.65	50	750 1.4	1.2	25 2.0	2300	5100	1.9	1.3 2.8
BURMAN R B10	49 36 125 50	55	4.4	.65	50	250 1.0	13	138 26	1600	4400	2.4	1.4 4.2
BUTTERWORT/ELK CR B5	49 48 125 53	33	2.6	.65	50	375 .91	6.5	138 6.3	950	3200	2.9	1.7 5.0

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
CAMERON R C11	49 15 124 40	78	6.2	.55	50	250 1.2	0.3	25 9.0	2200	3000	1.4	0.7 2.7
CANTON CR C7	49 49 126 28	31	3.1	.65	30	800 1.2	1.4	138 1.5	680	4500	5.7	3.5 9.3
CANTON CR EAST C5	49 50 126 28	11	1.1	.65	30	150 .61	3.4	138 4.4	240	1500	5.2	3.2 8.4
CANTON CR WEST C6	49 50 126 28	20	2.0	.65	30	300 .86	4.0	138 4.0	440	2400	4.6	2.8 7.5
CATHERINE CR C3	50 25 126 36	47	3.0	.68	90	1100 1.0	11	138 19	1970	6500	2.8	1.5 5.1
CERVUS CR @ LADY F C8	49 51 125 47	55	5.5	.65	100	380 1.1	0.9	138 1.6	3900	3800	0.8	0.5 1.2
CIRIACO CR C4	49 56 126 49	3.5	.49	.65	90	550 .46	6.0	25 8.0	320	2000	5.2	3.4 8.1
CLUXEWE R C1	50 29 127 09	23	1.8	.65	60	550 .82	2.5	25 11	800	2600	2.8	1.6 4.9
COMOX CR C10	49 32 125 15	28	2.0	.65	50	125 .67	0.8	25 18	720	1500	1.7	1.1 2.7
CRAFT CR C2	50 24 127 15	15	1.2	.65	180	1800 .71	3.0	25 18	1500	4000	2.2	1.3 3.8
CRUICKSHANK R C9	49 36 125 15	77	5.4	.65	150	2000 1.3	0.1	25 18	5800	8900	1.3	0.9 2.1
DICK BOOTH CR D1	50 41 127 31	18	1.3	.68	90	1500 .82	2.5	25 2.5	880	5000	4.7	2.6 8.5
DRINKWATER CR D2	49 26 125 30	26	3.3	.62	50	250 .92	8.0	138 23	1100	3300	2.6	1.6 4.0
EHATISAHT CR E1	49 53 126 51	11	1.5	.65	60	800 .82	13	25 17	670	4600	6.0	3.9 9.2
NGLISHMAN R E2	49 15 124 21	149	10	.55	50	1630 2.0	1.0	25 2.3	3700	11300	3.1	1.7 5.7

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
FAIRY CR F2	48 36 124 20	7	.55	.51	50	125 .44	0.5	25 5.5	200	820	4.5	2.7 7.4
FELLOWS CR F4	48 40 123 53	9	.45	.51	50	250 .44	0.5	25 15	160	710	4.8	2.2 11
FLEET R F3	48 35 124 03	64	5.0	.51	50	750 1.3	1.0	25 24	1800	5000	3.1	1.9 5.0
FRIEND CR F1	49 58 126 48	2.5	.38	.65	90	300 .41	0.6	25 3.0	260	960	3.2	2.2 4.9
GOLD R G1	49 52 126 06	198	20	.65	30	900 2.5	0.6	138 4.4	4400	13000	2.6	1.7 3.9
HANDY CR H7	49 00 124 56	32	3.8	.62	100	310 .89	1.0	25 29	2700	2900	1.0	0.6 1.7
HEADQUARTERS CR H4	49 42 125 07	24	1.5	.65	50	250 .68	0.8	25 1.4	540	1400	2.3	1.4 3.5
HECTATE LAKE H1	49 53 126 47	8.0	1.1	.65	30	500 .76	0.6	25 16	240	1900	6.9	4.4 11
HENSHAW CR #1 H5	49 36 125 32	33	2.5	.65	50	500 .94	1.6	138 43	890	2900	2.8	1.6 4.9
HENSHAW CR #2 H6	49 36 125 32	34	2.6	.65	50	500 .95	0.5	138 43	910	2800	2.6	1.5 4.6
HESQUIAT PT CR H3	49 25 126 23	15	1.5	.65	40	700 .87	1.5	25 38	440	3100	6.1	3.8 10
HOISS CR H2	49 42 126 34	12	1.3	.65	60	950 0.8	2.0	138 17	570	3000	4.7	3.1 7.0
KAIPIT CR K9	50 15 126 48	81	9.7	.65	60	700 1.6	0.3	138 6.0	4200	7000	1.4	0.9 2.3
KAOUK R K10	50 05 126 52	30	3.6	.65	60	1400 1.3	1.4	25 18	1600	7300	4.1	2.6 6.4
KASHULT R K3	50 12 127 19	19	1.5	.64	60	950 .83	2.0	25 32	630	3700	5.1	3.1 8.3

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
KAUWINCH R K2	50 14 127 16	16	1.2	.64	120	900 .68	7.0	25 24	1000	3310	2.8	1.7 4.5
KENDRICK CR K12	49 44 126 39	16	1.6	.65	30	620 .91	1.0	138 23	350	2900	7.2	4.8 11
KILPALA R K1	50 26 127 03	52	4.1	.65	60	1700 1.4	13	25 17	1800	9700	4.7	2.7 8.0
KINMAN CR K7	50 21 126 55	23	1.5	.68	90	1050 0.8	1.4	138 21	980	3200	2.7	1.5 5.0
KOKISH R K5	50 28 126 48	84	5.5	.68	60	1400 1.5	1.7	138 2.8	2390	8500	3.0	2.1 4.3
KOKISH R K4	50 29 126 50	265	17	.68	30	950 2.4	0.0	138 0.7	3700	15000	3.3	2.3 4.9
KOKISH R K11	50 31 126 52	282	18	.68	90	1150 2.1	2.5	138 0.5	12000	17000	1.2	0.8 1.7
KOKISH R K6	50 27 126 47	80	5.2	.68	127	1900 1.3	2.0	138 3.0	4700	9900	1.7	1.2 2.5
KUNNUM CR K8	50 18 126 14	48	2.9	.64	91	2050 1.2	2.5	25 27	1900	9000	4.2	2.2 8.1
LEINER R L1	49 56 126 37	58	8.1	.65	30	350 1.5	2.0	25 4.0	1700	4800	2.4	1.5 3.7
LUTES CR L2	49 53 126 46	11	1.5	.65	60	450 .74	7.5	25 14	670	2800	3.6	2.3 5.5
MACKTUSH CR M17	49 06 124 51	24	2.9	.62	50	625 1.0	0.2	25 10	1000	3000	2.6	1.5 4.5
MALKSOPE R M4	50 10 127 22	15	1.1	.64	60	1050 .77	1.8	25 26	490	3100	5.5	3.4 9.0
MAMAT CR M8	49 59 126 55	4.5	.63	.65	60	600 .56	1.3	25 6.0	270	1700	5.3	3.4 8.1
MAQUILLA CR M7	50 05 126 25	45	3.4	.64	90	1650 1.2	1.3	138 0.8	2200	7700	3.1	1.9 5.0

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
MARBLE R M3	50 16 127 20	12	.93	.65	60	900 .70	8	25 17	400	3000	6.4	3.9 11
MARBLE R CANYON M1	50 26 127 23	128	11	.70	33	1700 2.2	0.5	25 5.0	2580	16000	5.2	3.5 7.5
MARGARET CR M16	49 26 125 27	23	2.9	.62	50	250 .87	8.0	138 23	1000	3200	2.8	1.8 4.3
MATCHLEE CR M12	49 39 126 03	14	1.4	.65	40	100 .59	10	25 11	400	2400	5.1	3.1 8.3
MAYNARD L M2	50 24 127 14	114	9.1	.65	64	550 1.5	0.0	25 18	4190	5400	1.1	0.6 1.9
McKELVIE CR M9	49 56 126 39	20	2.4	.65	90	600 .86	0.5	25 4.0	1580	3100	1.7	1.1 2.7
MEGIN R TRIBUTARY M13	49 32 126 01	13	1.3	.65	40	275 .69	10	25 47	380	2600	6.0	3.7 9.8
MEMEKAY R M14	50 10 125 47	103	4.1	.67	50	1000 1.3	0.3	25 7.5	1400	5400	3.1	1.5 6.2
MOAKWA CR M6	50 07 126 02	41	3.1	.64	90	1250 1.1	1.4	138 22	2000	5900	2.6	1.6 4.2
MONTAGUE CR M5	50 20 126 12	37	2.2	.64	152	1500 .90	3.0	25 22	2400	5800	2.1	1.1 4.1
MOOYAH R M11	49 37 126 25	17	1.7	.65	40	900 .95	0.0	25 32	490	3800	6.7	4.1 11
MUCHALAT R M10	49 53 126 19	20	2.0	.65	60	350 .78	5.0	138 12	880	2500	2.4	1.5 4.0
MYRA CR AT FALLS M15	49 35 125 34	70	5.3	.65	50	1200 1.5	0.9	138 40	1800	7200	3.3	1.9 5.9
NAKA CR N2	50 28 126 25	53	3.2	.64	60	750 1.1	11	138 31	1400	5500	3.5	1.8 6.7
NARROWGUT CR N1	50 00 127 07	18	1.8	.65	30	400 .87	6.0	25 27	390	2900	6.4	4.3 9.5

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
NEWCASTLE CR N3	50 22 126 07	33	2.0	.64	90	850 .85	1.1	25 15	1300	3600	2.4	1.3 4.7
NORA CR N4	50 08 126 02	15	1.1	.64	152	1200 .67	1.5	25 22	1200	3100	2.2	1.4 3.6
NOR/MID MEMEKAY R N5	50 11 125 47	103	4.1	.67	50	1250 1.3	3.0	25 5.5	1400	6800	3.9	1.9 7.9
OKTWANCH R O2	49 47 126 15	16	1.6	.65	30	400 .83	0.6	138 0.9	340	2100	5.2	3.2 8.4
OUOUKINSH R O1	50 13 127 25	12	.92	.64	120	1100 .63	8.0	25 21	800	3500	3.9	2.4 6.2
PALMERSTON CR P2	50 27 126 16	29	1.7	.64	90	725 .79	1.5	25 28	1100	2800	2.1	1.2 4.1
PEGGATTEM CR P1	50 38 127 59	20	1.5	.68	30	550 .87	0.9	25 29	320	2600	6.6	3.8 11.6
PERRY R P4	49 54 126 37	37	5.2	.65	30	600 1.4	0.0	25 3.0	1140	4900	3.8	2.4 5.8
PHILLIPS CR P7	49 40 125 34	80	8.0	.65	50	500 1.5	13	138 27	2800	6900	2.1	1.4 3.2
PIGGOTT CR P6	49 49 125 22	82	5.3	.65	50	250 1.1	0.7	25 14	1900	2800	1.3	0.8 2.0
PINDER CR P3	50 15 126 55	25	3.0	.65	90	2100 1.2	0.7	138 16	1900	9000	4.0	2.6 6.4
PRETTY GIRL L P5	49 30 126 14	17	1.7	.65	80	400 .72	2.0	25 32	980	2200	1.9	1.2 3.1
RALPH R R1	49 38 125 31	23	1.7	.65	50	375 .78	1.3	138 39	620	1900	2.6	1.5 4.6
ROSEWALL CR R2	49 27 124 48	39	2.9	.62	100	630 .91	1.3	25 1.0	2100	3200	1.4	0.7 2.6
SALMON R S3	50 05 126 41	241	7.5	.67	50	700 1.5	0.0	25 19	2700	5700	1.8	1.2 2.6

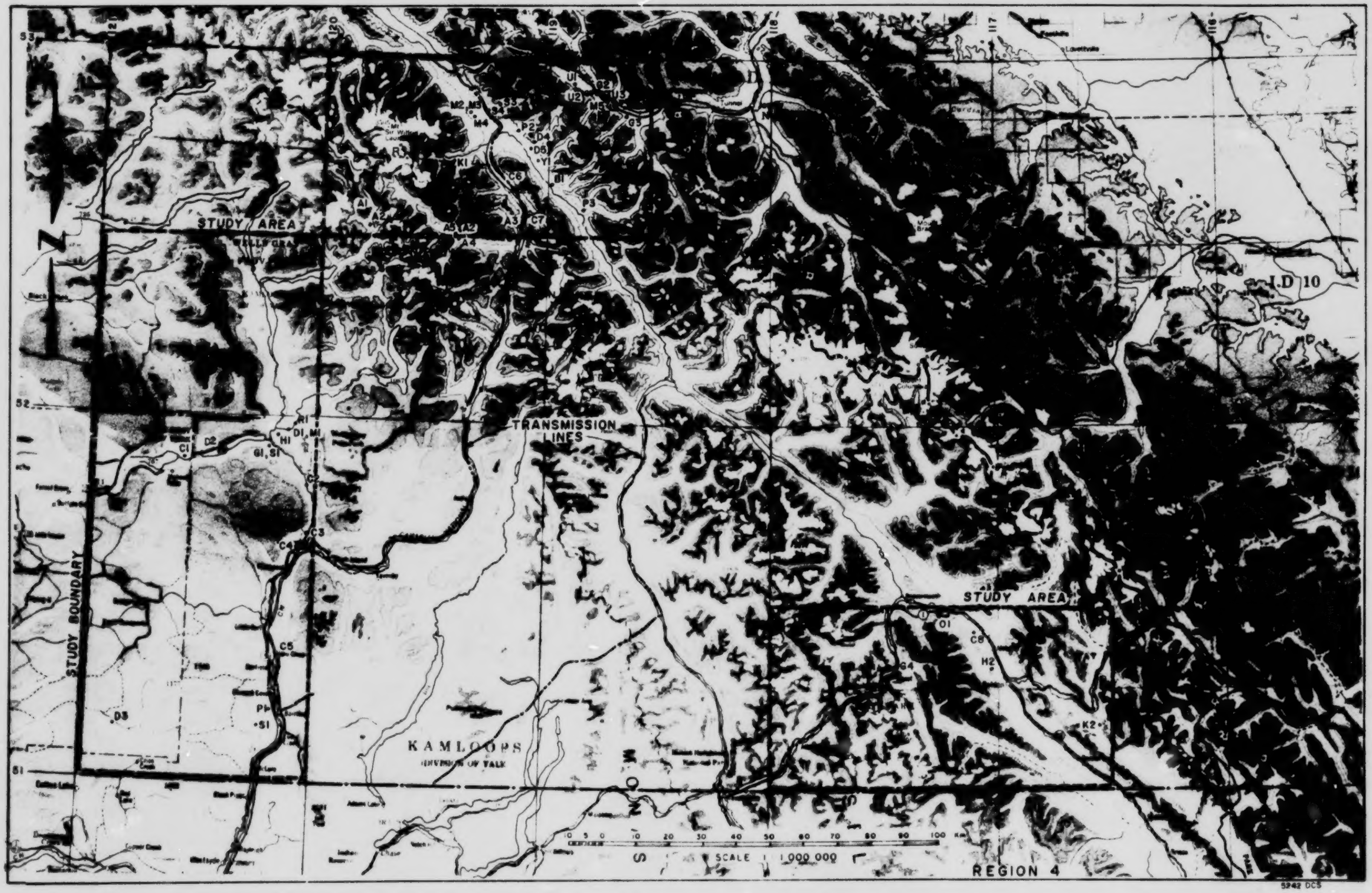
BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
SAN JUAN R S10	48 36 123 59	45	2.3	.51	50	750 .97	1.5	25 18	810	2800	3.8	1.8 8.2
SAUNDERS CR S5	49 48 126 01	31	3.1	.65	90	1200 1.1	0.1	138 2.0	2000	5300	2.2	1.4 3.6
SEBALHALL CR S6	49 47 126 24	25	2.5	.65	30	400 .99	3.0	138 10	560	2800	4.4	2.7 7.1
SHEPHERD CR S7	49 38 125 31	43	3.2	.65	50	500 1.0	0.7	138 39	1200	3200	2.4	1.4 4.2
SHUSHARTIE R S1	50 49 127 52	65	4.9	.68	30	750 1.4	3.0	25 28	1000	5900	4.6	2.6 8.1
SOMBRIO R S9	48 31 124 17	11	.87	.51	50	380 .60	0.0	25 0.5	310	1300	4.5	2.8 7.4
SONGHEES CR S2	50 47 127 35	60	4.5	.68	30	450 1.3	3.0	25 8.0	990	4200	3.6	2.0 6.3
SOUTH ENGLISHMAN R S8	49 15 124 17	66	4.6	.55	100	2000 1.3	0.1	25 5.0	3300	8400	2.6	1.4 4.8
SWAH CR S4	50 01 126 20	14	1.4	.65	60	700 .78	0.0	138 1.9	620	2300	3.1	1.9 5.0
TABOLT CR TRIB T6	49 30 126 06	15	1.5	.65	40	250 .71	2.0	25 28	430	1800	3.5	2.2 5.7
TAHSISH R T3	50 13 127 03	40	3.0	.64	60	500 .97	0.8	138 45	1300	3200	2.2	1.3 3.5
TAHSISH R T2	50 16 127 05	47	3.7	.65	30	500 1.2	0.5	138 45	810	3300	3.5	2.1 6.1
TEIHSUM R T1	50 20 127 21	29	2.3	.65	60	1700 1.1	2.0	25 17	1000	6500	5.6	3.2 9.8
THELWOOD CR T8	49 33 125 34	39	2.9	.65	100	1000 1.0	0.3	138 41	2100	4500	1.9	1.1 3.3
TLATLOS CR T4	50 23 126 14	35	2.1	.64	182	2275 .92	3.0	25 26	2700	8000	2.6	1.3 4.9

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
TLOOLS CR T7	49 52 125 45	40	3.0	.65	50	625 1.1	1.0	138 1.0	1070	3500	2.8	1.6 5.0
TLUPANA R T5	49 46 126 20	29	2.9	.65	90	1850 1.1	2.0	138 2.0	1900	7700	3.6	2.2 5.8
TRENT R T9	49 35 124 59	28	2.0	.65	50	880 .95	0.3	25 4.0	700	3200	3.9	2.5 6.0
TSABLE R T10	49 31 124 54	97	6.8	.65	50	500 1.4	0.0	25 4.0	2400	4200	1.5	1.0 2.2
TUGWELL CR T11	48 25 123 50	13	.65	.51	50	625 .59	0.3	25 5.0	230	1200	5.6	2.6 12
UCONA R U41	49 44 125 57	66	6.6	.65	50	200 1.1	0.0	138 10	2300	3200	1.2	0.8 1.7
UNNAMED CR U19	50 04 126 11	11	.80	.64	90	1200 .65	10	138 12	530	3800	6.3	3.9 10
UNNAMED CR U33	49 23 126 04	8	.77	.65	40	300 .57	1.5	25 17	220	1400	5.3	3.3 8.7
UNNAMED CR U5	50 08 127 11	30	2.3	.64	30	500 .99	4.5	25 38	490	3400	6.0	3.7 9.7
UNNAMED CR U30	49 27 126 05	6	.57	.65	40	220 .48	2.0	25 30	160	1200	6.3	3.9 10
UNNAMED CR U2	50 29 127 21	15	1.2	.65	90	600 .65	3.0	25 10	770	2100	2.4	1.4 4.0
UNNAMED CR U31	49 24 126 17	4	.38	.65	40	150 .41	1.5	25 29	110	930	7.2	4.4 12
UNNAMED CR U4	50 18 127 12	13	1.0	.65	90	600 .62	5.0	25 27	670	2200	2.9	1.6 5.2
UNNAMED CR U21	49 57 126 25	18	1.8	.65	30	170 .74	2.5	138 9.0	380	1700	3.7	2.3 6.1
UNNAMED CR U26	49 48 126 25	12	1.2	.65	30	200 .65	0.6	138 0.5	250	1300	4.3	2.6 7.0

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
UNNAMED CR U6	49 52 127 05	11	1.1	.65	60	720 .71	1.2	25 30	480	2300	4.1	2.8 6.1
UNNAMED CR U12	50 10 126 20	10	.74	.64	244	1450 .54	2.0	138 13	1300	3000	2.1	1.3 3.3
UNNAMED CR U9	50 21 126 07	19	1.2	.64	120	1000 .68	1.5	25 19	1000	2800	2.4	1.3 4.6
UNNAMED CR U32	49 52 126 50	7.3	1.0	.65	30	350 .69	1.0	25 19	220	1600	6.0	3.9 9.3
UNNAMED CR U22	49 55 126 48	3.5	.49	.65	30	90 .44	7.0	25 9.0	110	1500	11	7.4 17
UNNAMED CR U29	49 29 126 14	17	1.7	.65	80	400 .72	2.0	25 30	980	2200	1.9	1.2 3.1
UNNAMED CR U23	49 23 126 07	4	.41	.65	40	400 .48	1.5	25 13	110	1300	9.3	5.7 15
UNNAMED CR U27	49 47 126 44	10	1.5	.65	60	1150 .87	3.0	138 19	640	4400	6.0	3.9 9.2
UNNAMED CR U16	50 07 126 36	14	1.7	.65	120	1000 .78	8.0	138 9.0	1400	4100	2.4	1.5 3.8
UNNAMED CR U10	50 20 126 26	19	1.1	.64	120	1000 .67	14	138 23	1000	4300	3.8	2.0 7.3
UNNAMED CR U1	50 29 122 22	15	1.2	.65	180	1850 .71	3.0	25 8.0	1500	4100	2.3	1.3 4.0
UNNAMED CR U17	50 05 126 25	27	2.0	.64	60	1250 .99	0.0	138 0.8	890	5000	5.0	3.1 8.1
UNNAMED CR U13	50 10 126 37	17	2.0	.65	90	1200 .92	1.0	138 7.0	1300	4700	3.1	1.9 4.8
UNNAMED CR U40	49 46 125 41	33	2.5	.65	200	1060 .83	13	138 20	3500	6100	1.5	0.9 2.6
UNNAMED CR U28	49 39 126 04	14	1.4	.65	40	100 .59	5.0	25 5.0	400	1800	3.9	2.4 6.3

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
UNNAMED CR U7	50 30 126 54	22	1.4	.68	60	500 .73	0.8	138 1.6	620	2000	2.6	1.4 4.8
UNNAMED CR U34	49 21 126 01	4	.37	.65	40	250 .44	4.5	25 16	110	1400	11	6.6 17
UNNAMED CR U14	50 10 126 18	19	1.4	.64	90	800 .74	1.3	138 14	940	2600	2.5	1.5 4.0
UNNAMED CR U38	50 11 125 24	19	.80	.67	100	1400 .65	10	25 9.0	570	3900	5.7	2.8 12
UNNAMED CR U15	50 08 126 37	18	2.2	.65	60	675 .91	1.8	138 11	960	3500	3.1	2.0 4.9
UNNAMED CR U11	50 13 126 05	12	.90	.64	55	900 .69	1.5	25 13	350	2500	6.3	3.9 10
UNNAMED CR U18	50 05 126 28	20	1.5	.64	90	1320 .83	1.5	138 1.2	980	4600	4.1	2.5 6.7
UNNAMED CR U20	49 57 126 51	3	.43	.65	122	700 .44	0.0	25 5.0	380	1400	3.2	2.1 4.9
UNNAMED CR U39	49 50 125 38	25	.90	.65	50	375 .61	2.0	138 14	320	1500	4.1	2.3 7.2
UNNAMED CR U35	49 19 126 05	4	.41	.65	80	550 .44	0.7	25 4.5	230	1300	4.8	3.0 7.8
UNNAMED CR U8	50 29 126 24	21	1.3	.64	152	1250 .70	10	138 33	1380	4400	2.8	1.5 5.3
UNNAMED CR U25	49 48 126 17	20	2.0	.65	30	400 .90	0.5	138 1.5	430	2300	4.5	2.8 7.3
UNNAMED CR U36	49 17 126 10	8	.84	.65	40	600 .67	2.5	25 6.5	240	2100	7.6	4.7 12
UNNAMED CR U37	49 17 126 10	8	.79	.67	40	375 .60	2.5	25 6.5	220	1600	6.0	3.7 9.7
UPANA CR U24	49 48 126 05	58	5.8	.65	30	800 1.5	0.1	138 0.1	1300	5900	4.1	2.5 6.7

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
UTLUH CR U3	50 19 127 25	19	1.5	.65	60	920 .84	10	25 10	640	4200	5.7	3.2 10
WADY CR W1	50 24 127 17	15	1.2	.65	180	825 .61	6.5	25 16	1500	3000	1.7	1.0 2.9
WALT LAKE CR W5	49 53 124 08	14	.70	.65	150	600 .49	0.5	25 16	750	1500	1.8	0.8 3.8
WARD CR W2	49 47 126 04	8.5	.86	.65	30	200 .58	0.4	138 0.4	180	1000	4.8	3.0 7.8
WHITE R W4	50 18 125 56	350	17.5	.67	50	950 2.2	0.0	25 2.0	6300	13000	1.7	0.9 3.2
WILFRED CR W6	49 28 124 51	20	1.5	.62	50	313 .71	0.0	25 3.5	540	1400	2.4	1.2 4.6
WILSON CR W3	49 39 126 10	14	1.4	.65	40	400 .76	1.0	25 11	400	1900	4.1	2.5 6.6
YOOKWA CR Y1	50 04 126 28	34	2.5	.64	30	800 1.1	1.5	138 3.0	550	4400	7.0	4.3 11
ZEBALLOS L Z2	50 03 126 46	45	5.4	.65	90	1250 1.3	2.3	25 10	3500	7800	1.9	1.2 3.0
ZEBALLOS R Z1	50 03 126 47	47	5.6	.65	60	800 1.3	0.0	25 10	2400	5800	2.1	1.3 3.2
ZEBALLOS(LITTLE) R Z3	49 59 126 45	9	1.5	.65	210	750 .64	0.4	25 6.0	2300	2620	1.0	0.6 1.7


STUDY AREA
TRANSMISSION LINES
STUDY AREA
STUDY BOUNDARY
KAMLOOPS
DIVISION OF YALE
I.D 10
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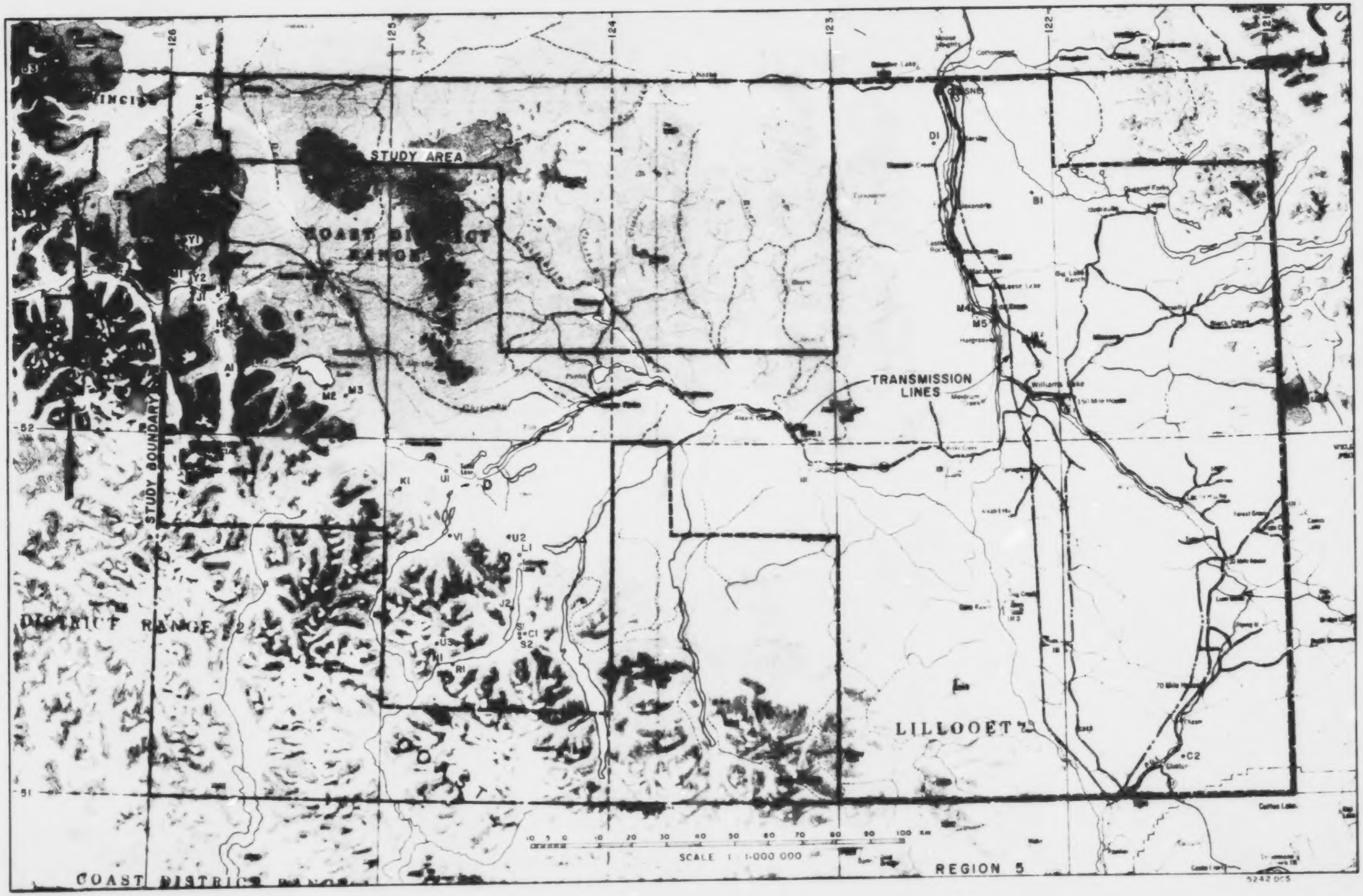
53
52
51
120
119
118
117
116
MONS
SCALE 1 : 1 000 000
10 5 0 10 20 30 40 50 60 70 80 90 100 Km
REGION 4
5242 DCS

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
ADOLPH CR #1 A4	52 31 119 23	80	2.8	.50	213	3400 1.1	6.0	25 29	4300	13600	3.6	2.0 6.5
ADOLPH CR #2 A5	52 31 119 24	78	2.7	.50	61	700 1.0	6.0	25 29	1200	4200	4.0	2.2 7.2
ALLAN CR A3	52 32 119 07	122	4.3	.50	91	1900 1.3	2.0	25 12	2800	9300	3.8	2.1 6.7
AZURE R #1 A1	52 35 119 48	98	3.4	.50	61	800 1.1	31	25 60	1500	8400	6.4	3.6 11
AZURE R #2 A2	52 32 119 47	228	8.0	.50	30	900 1.8	28	25 60	1700	11500	7.5	4.2 13
BULLDOG CR B1	52 39 118 59	104	3.6	.50	152	875 .97	18	25 26	3900	7100	2.0	1.1 3.7
CAMP CR C6	52 39 119 11	74	2.6	.50	91	1100 .98	2.0	25 2.0	1700	4700	3.2	1.8 5.7
CANIM FALLS C1	51 53 120 35	N/A	18	.44	N/A	N/A N/A	0.8	25 0.8	N/A	N/A	N/A	N/A N/A
CHUA CHUA CR C5	51 21 120 07	104	.50	.43	450	1900 .44	2.0	25 2.0	1500	3100	2.7	1.6 4.4
CIRQUE CR C8	51 26 117 06	20	.40	.52	123	700 .44	5.0	25 2.0	360	1900	5.6	2.1 15
CLEARWATER RAPID-1 C2	51 49 120 03	N/A	210	.44	N/A	N/A N/A	0.0	25 N/A	N/A	N/A	N/A	N/A N/A
CLEARWATER RAPID-2 C3	51 41 120 02	N/A	225	.44	N/A	N/A N/A	0.0	25 N/A	N/A	N/A	N/A	N/A N/A
CLEARWATER RAPID-3 C4	51 39 120 04	N/A	227	.44	N/A	N/A N/A	0.0	25 1.0	N/A	N/A	N/A	N/A N/A
CLEMINA CR C7	52 34 119 05	70	2.5	.50	152	1300 .90	2.0	25 10	2700	5000	2.1	1.2 3.9
DAVE HENRY CR #1 D4	52 46 119 04	92	3.2	.50	61	850 1.1	3.0	25 15	1400	4600	3.7	2.1 6.7

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
DAVE HENRY CR #2 D5	52 45 119 05	99	3.5	.50	91	550 .97	5.5	25 11	2300	4000	2.0	1.1 3.6
DAWSON FALLS D1	51 58 120 08	1378	44	.44	N/A	N/A N/A	0.0	25 22	N/A	N/A	N/A	N/A N/A
DEADMAN R @ FALLS D3	51 09 120 51	246	.60	.43	N/A	N/A N/A	1.0	25 24	N/A	N/A	N/A	N/A N/A
DECEPTION FALLS D2	51 54 120 28	N/A	34	.44	N/A	N/A N/A	0.8	25 5.5	N/A	N/A	N/A	N/A N/A
GHITA CR G3	52 51 118 39	76	2.7	.50	306	2750 .94	3.0	25 31	5800	11500	2.2	1.3 4.0
GOODWIN FALLS G1	51 55 120 13	4714	30	.44	N/A	N/A N/A	0.5	25 15	N/A	N/A	N/A	N/A N/A
GRANT BROOK G2	52 54 118 45	111	3.9	.50	152	1500 1.1	2.0	25 21	4200	6900	1.8	1.0 3.3
GRIZZLY CR G4	51 19 117 25	75	3.0	.52	305	3400 1.0	7.0	25 50	6500	16800	2.8	1.1 7.4
HELMCKEN FALLS H1	51 57 120 10	1384	45	.44	N/A	N/A N/A	0.3	25 19	N/A	N/A	N/A	N/A N/A
HOLT CR H2	51 20 117 01	42	.80	.52	92	1500 .68	5.0	25 3.0	550	3600	7.0	2.7 19
KICKING HORSE FALL K2	51 11 116 34	N/A	N/A	N/A	N/A	N/A N/A	1.0	25 30	N/A	N/A	N/A	N/A N/A
KIMMEL CR K1	52 43 119 25	47.5	1.7	.50	91	820 .79	11	25 10	1100	4000	4.1	2.3 7.4
McLENNAN R @ N.ARM M3	52 51 119 21	95	3.3	.50	61	1250 1.2	6.0	25 5.5	1460	6600	5.2	2.9 9.3
McLENNAN R M4	52 50 119 20	139	4.9	.50	30	800 1.4	2.5	25 4.0	1070	5800	6.2	3.4 11
McLENNON R @S.ARM M2	52 51 119 21	40	1.4	.50	244	1450 .69	5.0	25 6.0	2500	4100	1.9	1.0 3.5

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
MOOSE R M5	52 55 118 48	464	16	.50	61	550 1.8	0.8	25 15	6800	7700	1.3	0.9 1.9
MUSHROOM RAPIDS M1	51 58 120 08	1378	44	.44	N/A	N/A N/A	0.0	25 22	N/A	N/A	N/A	N/A N/A
OLDMAN CR O1	51 29 117 15	24	.50	.52	123	750 .46	6.0	25 5.0	420	2100	5.3	2.0 14
PACKSADDLE CR P2	52 48 119 08	46	1.6	.50	122	1250 .80	4.0	25 7.5	1400	3760	3.0	1.8 5.3
PETERSON CR P1	51 12 120 10	125	.30	.43	100	300 .36	0.3	25 3.0	230	770	4.5	2.8 7.3
PTARMIGAN CR P3	52 35 118 50	272	9.5	.50	61	1600 1.8	2.5	25 40	4100	12800	3.5	2.0 6.3
RAPIDS ON MURTLE R R1	51 59 120 06	1370	43	.44	N/A	N/A N/A	0.0	25 23	N/A	N/A	N/A	N/A N/A
SKULL CR S2	51 09 120 13	70	.18	.43	100	250 .30	1.0	25 7.0	130	700	6.8	3.3 14
SWIFT CR #1 S3	52 52 119 13	110	3.3	.50	91	1325 1.1	6.0	25 5.0	2100	6500	3.4	2.3 5.2
SWIFT CR #2 S4	52 51 119 16	126	3.7	.50	61	1425 1.3	2.1	25 0.9	1600	7100	5.0	3.3 7.5
SYLVIA FALLS S1	51 55 120 13	4714	30	.44	N/A	N/A N/A	0.5	25 15	N/A	N/A	N/A	N/A N/A
UNNAMED CR U1	52 56 118 53	75	2.6	.50	366	1420 .80	4.0	25 11	6800	7500	1.2	0.7 2.2
UNNAMED CR U2	52 55 118 53	74	2.6	.50	184	330 .71	4.0	25 11	3450	3100	1.0	0.6 1.8
UNNAMED CR U3	52 54 118 46	71	2.5	.50	152	520 .77	2.5	25 24	2700	2880	1.2	0.7 2.1
YELLOWJACKET CR Y1	52 43 119 03	94	3.3	.50	61	400 .96	0.8	25 17	1400	2800	2.3	1.3 4.0



STUDY AREA
STUDY BOUNDARY
TRANSMISSION LINES
COAST DISTRICT RANGE
LILLOOET
REGION 5
126
125
124
123
122
121
52
51
53
Williams Lake
Big Lake Ranch
70 Mile House
150 Mile House
Hargreaves
Meldrum Creek
Alexis Creek
Moose Heights
Cottonwood
D1
B1
M4
M5
M2
M3
A1
Y1
Y2
K1
U1
V1
U2
L1
J2
S1
C1
S2
U3
R1
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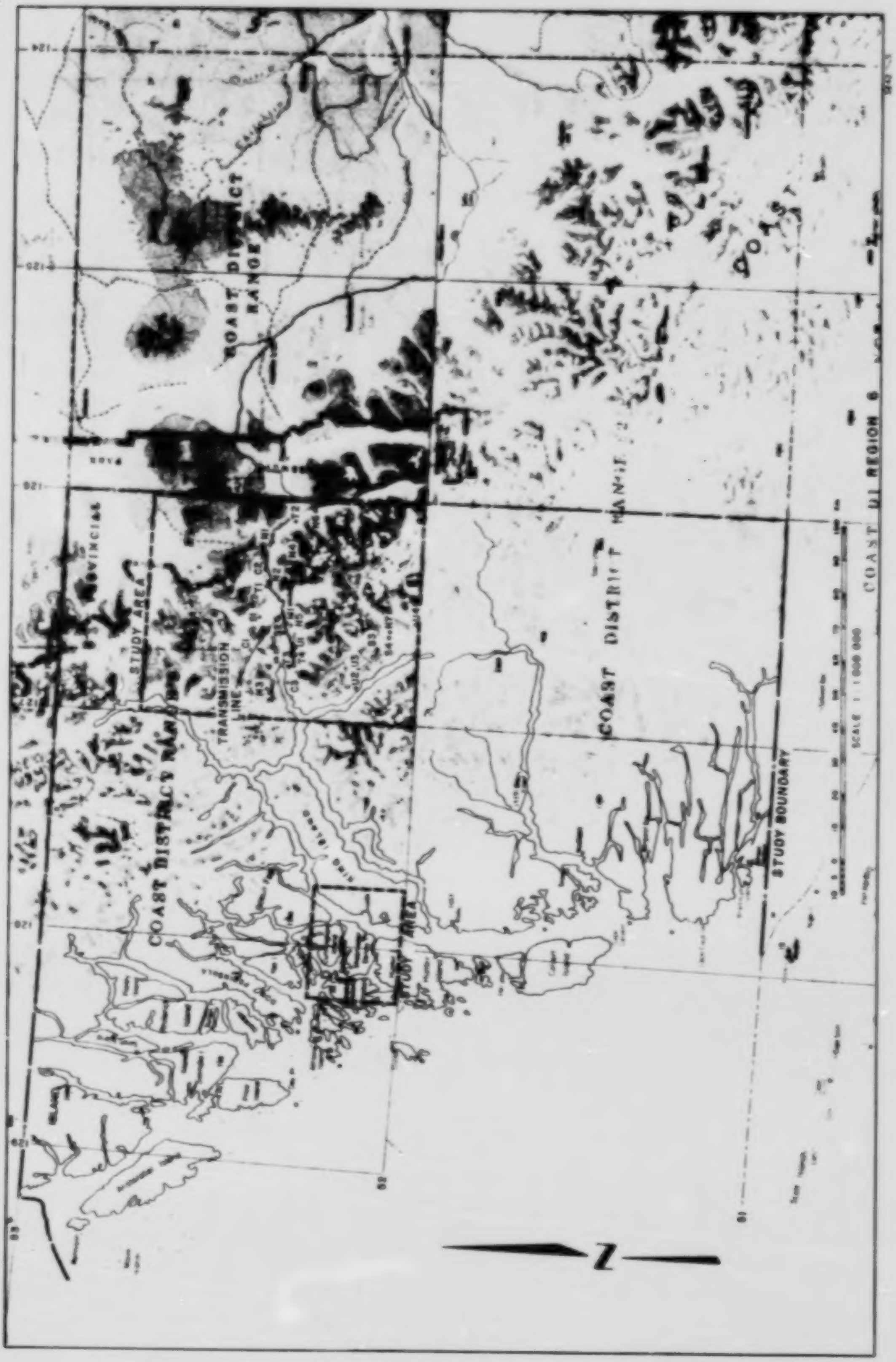
D
SCALE 1:1 000 000
10 5 0 10 20 30 40 50 60 70 80 90 100 km
5242 DCS

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
ATNARKO R A1	52 10 125 42	689	10	.60	275	3400 1.7	35	25 52	20000	46000	2.2	1.4 3.3
BEAVER CR @ FALLS B1	52 41 122 06	1200	3.0	.43	N/A	N/A N/A	2.0	25 18	N/A	N/A	N/A	N/A N/A
CHESHI CR C1	51 28 124 22	40	.80	.45	92	450 .54	5.0	25 22	530	1970	4.7	1.7 13
CLINTON FALLS C2	51 07 121 29	250	.40	.44	N/A	N/A N/A	0.0	25 4.0	N/A	N/A	N/A	N/A N/A
DESERTERS CR D1	52 49 122 32	105	.50	.37	100	220 .41	2.0	25 2.0	380	1100	4.2	2.0 8.6
HOTNARKO R H1	52 23 125 45	514	7.7	.60	153	2250 1.5	15	25 30	8500	18000	2.0	1.0 4.0
HUNLEN CR H2	52 17 125 45	117	2.8	.65	521	1200 .76	2.0	25 48	10500	8800	0.7	0.5 1.1
JAMISON CR J2	51 32 124 26	42	.40	.45	396	3400 .47	17	25 15	1200	6600	7.0	2.0 25
JANET CR J1	52 23 125 52	38	1.0	.65	610	1950 .53	4.0	25 32	4100	6600	1.4	0.6 3.0
KLINAKLINI CR K1	51 52 124 56	98	2.5	.45	61	650 .94	11	25 11	1070	4700	5.5	2.4 12
LINCOLN CR L1	51 41 124 24	14	.10	.45	213	1500 .31	3.0	25 2.0	220	1600	9.0	2.6 32
MACKIN CR M4	52 22 122 23	480	.50	.45	250	2000 .49	0.3	25 2.0	860	2700	3.9	1.5 10
MAYDOE CR M2	52 08 125 16	51	.70	.60	213	3250 .62	17	25 35	1030	7620	7.0	3.6 14
McCLINCHY CR M3	52 07 125 10	208	3.1	.60	30	800 1.2	10	25 33	670	5740	8.0	4.2 16
MCLEESE CR M5	52 20 122 17	150	.30	.45	150	1300 .45	0.0	25 0.0	360	1740	6.0	3.5 10

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
MOSHER CR M1	52 25 125 58	42	1.1	.65	457	2400 .60	3.0	25 32	3450	6700	1.7	0.8 3.7
NUDE CR FALLS N1	51 23 124 45	188	7.5	.50	N/A	N/A N/A	22	25 54	N/A	N/A	N/A	N/A N/A
RELIANCE CR R1	51 23 124 41	42	1.7	.50	92	350 .68	17	25 50	1100	4000	4.1	1.9 8.7
STIKELAN CR #1 S1	51 28 124 24	192	4.8	.45	31	450 1.3	1.5	25 22	1070	4200	4.9	1.9 13
STIKELAN CR #2 S2	51 27 124 22	110	3.3	.45	91	900 1.0	6.0	25 25	2100	5300	3.1	1.1 8.5
UNNAMED CR U1	51 55 124 44	60	.50	.40	61	750 .53	1.0	25 1.0	210	1600	11	4.0 28
UNNAMED CR U3	51 26 124 45	27	1.1	.50	336	1350 .58	30	25 60	2600	7430	3.3	1.5 7.0
UNNAMED CR U2	51 44 124 27	43	.40	.45	425	3700 .47	4.0	25 1.0	1310	5300	5.1	1.5 18
VALLEAU CR V1	51 44 124 43	120	1.2	.45	92	1050 .73	2.0	25 25	790	3010	4.8	1.8 13
YOUNG CR Y2	52 25 125 53	230	5.5	.65	457	2500 1.1	3.0	25 32	18000	23000	1.1	0.5 2.5
YOUNG CR @ RAPIDS Y1	52 32 125 54	83	1.2	.60	61	900 .78	7.0	25 20	540	3500	6.0	3.1 12


COAST DISTRICT RANGE
PROVINCIAL
STUDY AREA
TRANSMISSION LINE
COAST DISTRICT RANGE
STUDY AREA
COAST DISTRICT
COAST DISTRICT RANGE
COAST
COAST DI REGION 6
STUDY BOUNDARY
SCALE 1 : 1 000 000
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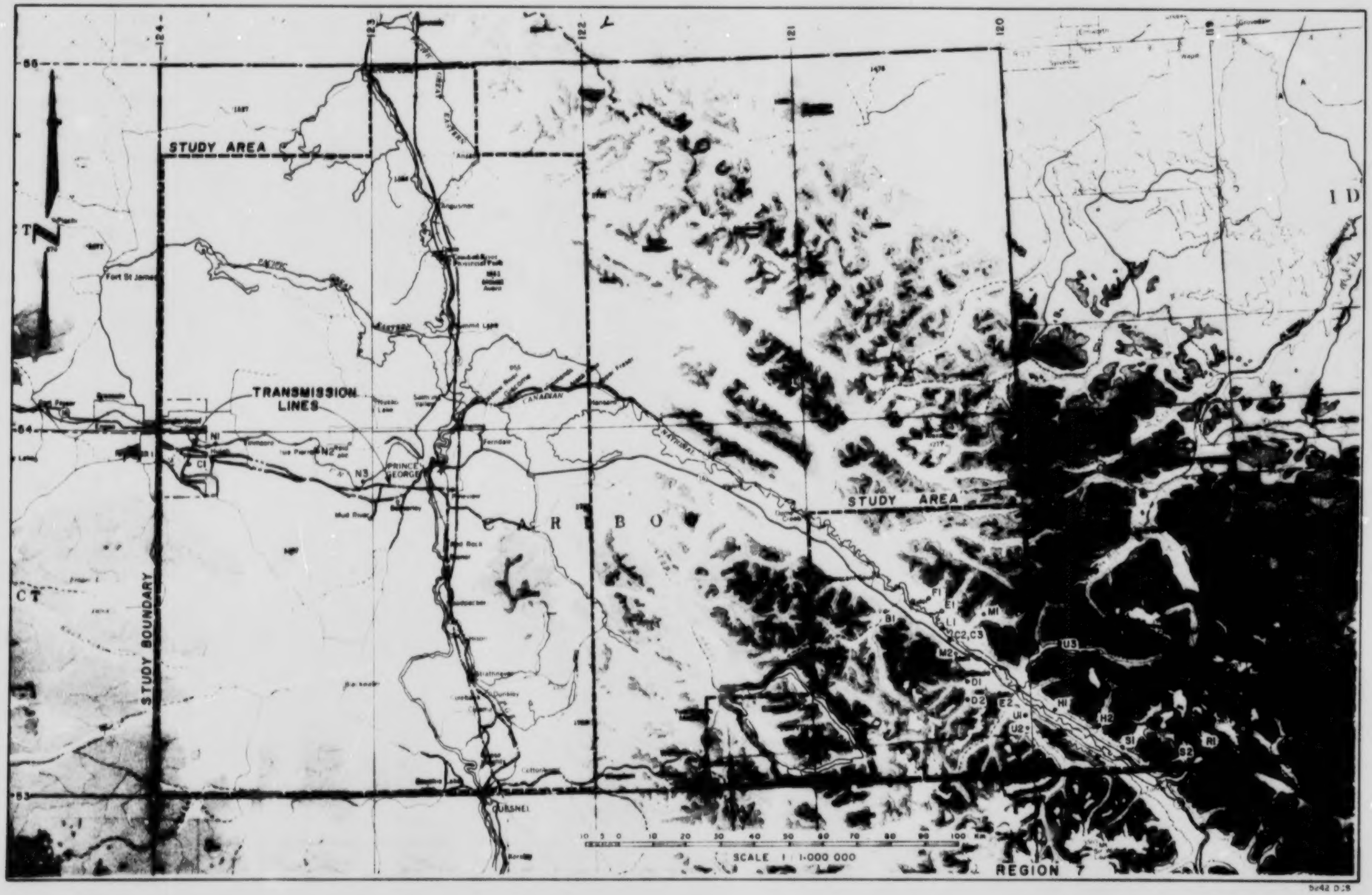
BC SMALL HYDRO ASSESSMENT	LAT LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
CACOOHTIN CR C2	52 26 126 19	42	1.7	.65	214	1200 .73	3.0	25 2.0	2590	3600	1.2	0.6 2.5
CHRISTENSON CR C1	52 28 126 41	40	2.8	.65	91	1400 1.1	15	25 12	1830	7620	3.6	2.0 6.6
CLAYTON FALLS CR C3	52 22 126 49	83	6.6	.65	61	700 1.4	1.0	25 0.0	2900	5500	1.6	1.0 2.7
MILL CR M1	52 24 126 34	15	1.1	.65	638	2200 .56	0.0	25 1.5	4800	6800	1.2	0.8 2.1
NIEUMIAMUS CR N3	52 25 126 51	29	2.5	.65	61	1450 1.1	4.0	25 10	1080	6400	5.2	3.2 8.3
NOEICK R N7	52 05 126 34	232	14	.65	122	2150 2.0	6.0	25 56	12200	24100	1.7	0.9 3.4
NOOMST CR #1 N4	52 23 126 15	53	1.3	.65	427	2950 .69	12	25 7.0	4070	9950	2.1	1.0 4.6
NOOMST CR #2 N1	52 26 126 13	96	3.4	.65	61	550 1.0	3.0	25 1.0	1480	3600	2.1	1.2 3.9
NOOSGULCH CR N2	52 26 126 23	125	8.4	.65	30	700 1.7	2.0	25 1.0	1800	6500	3.1	1.9 5.3
NOOKLIKONNIK CR N5	52 22 126 34	31	1.7	.65	366	2400 .75	5.0	25 2.0	4480	7900	1.5	0.9 2.8
NORDSCHOW CR N6	52 18 126 03	96	2.9	.65	183	1500 .95	10	25 20	3790	7030	1.6	0.8 3.2
SALLOOMT CR S1	52 27 126 32	135	8.6	.65	31	850 1.8	1.0	25 7.0	1910	7300	3.3	2.3 4.9
SMITELY R @ FALLS S4	52 05 126 36	265	18.6	.65	31	450 2.1	3.0	25 56	4100	9300	2.0	1.1 3.6
SMITELY R S3	52 07 126 39	213	15	.65	61	400 1.7	8.0	25 61	6500	8000	1.1	0.6 1.9
SNOOTLI CR S2	52 23 126 36	34	2.2	.65	152	1250 .86	2.0	25 0.5	2420	4530	1.6	1.0 2.8

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
TASTSQUAN CR T3	52 22 126 45	25	1.9	.65	91	250 .67	0.5	25 0.5	1200	1730	1.2	0.8 2.0
THORSEN CR T4	52 21 126 42	80	6.1	.65	80	1550 1.5	1.0	25 1.0	3500	8830	2.2	1.4 3.6
TSEAPSEAHOOLZ CR T1	52 26 126 24	25	1.3	.65	274	1900 .68	5.0	25 0.5	2470	4730	1.7	0.9 3.1
TSINI-TSINI CR T2	52 22 126 06	39	1.2	.65	213	1450 .66	5.0	25 12	1790	3800	1.9	1.0 3.6
UNNAMED CR U2	52 10 126 50	46	3.2	.65	152	1050 .96	1.5	25 31	3500	5000	1.3	0.7 2.3
UNNAMED CR U3	52 10 126 50	42	2.9	.65	396	3200 .96	4.0	25 31	8400	18000	1.9	1.0 3.4
UNNAMED CR U4	52 01 126 32	68	4.1	.65	214	1300 1.0	16	25 61	6280	9000	1.3	0.6 2.4
UNNAMED CR U1	52 21 126 40	5	.40	.65	1036	2700 .41	4.0	25 0.5	2800	7700	2.4	1.4 3.9

N
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STUDY AREA
STUDY AREA
STUDY BOUNDARY
TRANSMISSION LINES
PRINCE GEORGE
QUESNEL
Fort St James
CARIBOO
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NATIONAL
CANADIAN
PACIFIC
GREAT EASTERN
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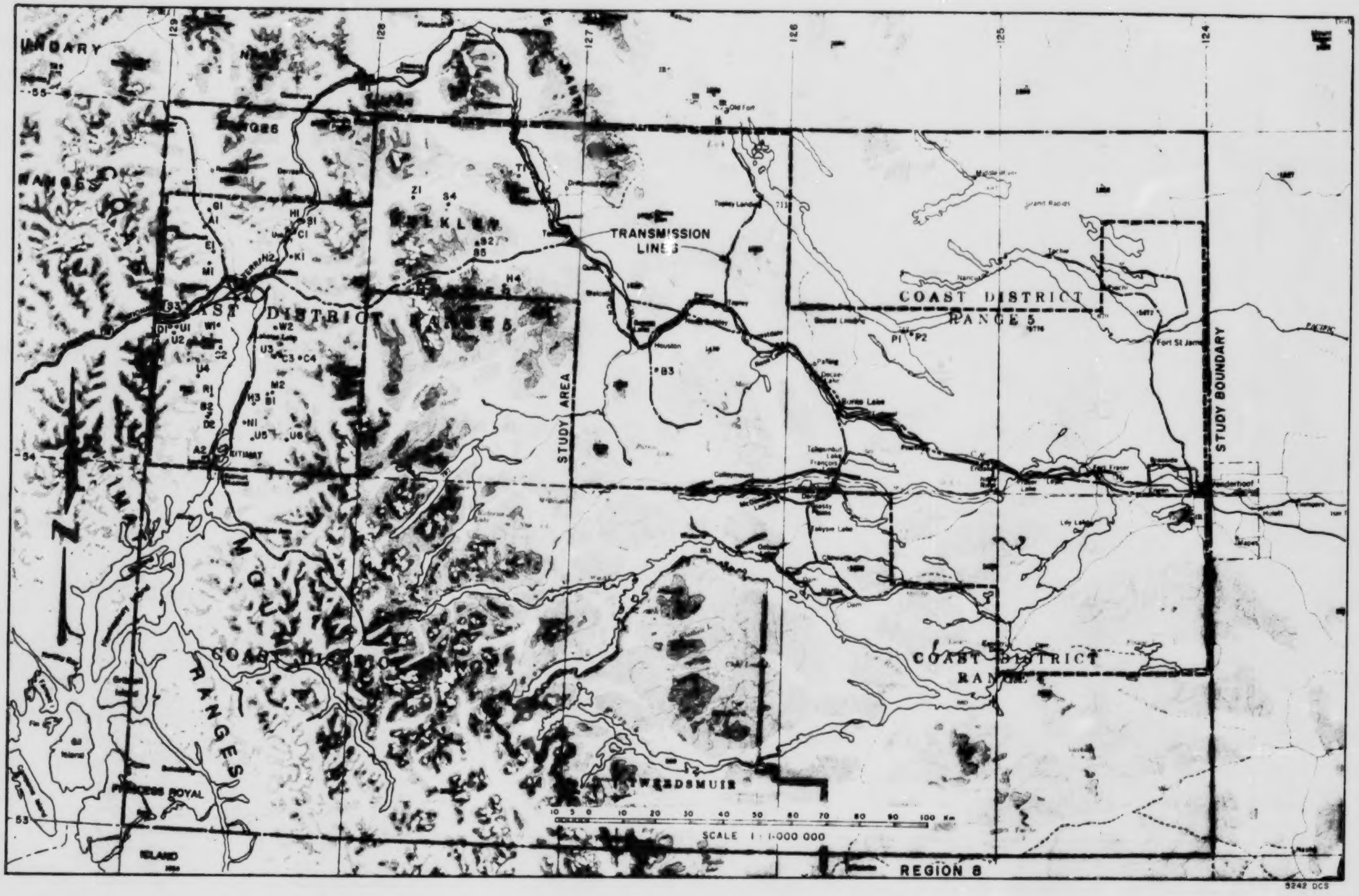
SCALE 1 : 1 000 000
REGION 7
5242 D.8

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
BOUNDING CR B1	53 28 120 39	16	.50	.50	92	800 .52	5.0	25 37	350	2200	7.0	4.5 11
CARROLE FALLS C1	53 58 123 51	N/A	N/A	.40	N/A	N/A N/A	0.5	25 1.5	N/A	N/A	N/A	N/A N/A
CLYDE CR #1 C2	53 23 120 22	30	1.1	.50	183	2250 .70	3.0	25 15	1400	4800	4.0	2.5 6.2
CLYDE CR #2 C3	5[illegible] 120 [illegible]	30	1.1	.50	91	900 .68	3.0	25 16	690	2600	4.2	2.7 6.6
DORE R #1 D1	53 16 120 17	178	6.8	.50	92	1600 1.5	1.7	25 13	4450	10300	2.6	1.8 3.9
DORE R #2 D2	53 13 120 17	137	5.2	.50	91	1500 1.4	6.0	25 17	3420	8830	2.9	2.0 4.3
EAST TWIN CR E1	53 28 120 23	112	3.9	.50	61	300 .98	2.0	25 22	1720	3000	2.0	1.2 3.1
EDDY CR E2	53 14 120 07	20	.70	.50	213	1000 .51	3.0	25 10	1070	2330	2.5	1.6 3.9
FLEET CR F1	53 30 120 27	58	2.0	.50	91	1500 .95	10	25 32	1300	6800	5.9	3.8 9.2
HOLLIDAY CR H1	53 11 119 53	52	1.8	.50	91	1400 .90	3.0	25 28	1190	5100	4.8	3.0 7.7
HORSEY CR H2	53 08 119 41	168	5.9	.50	122	2050 1.4	5.0	25 14	5150	11500	2.6	1.4 4.6
LEGRAND CR L1	53 25 120 23	13	.50	.50	152	1150 .49	2.0	25 22	550	2100	4.4	2.8 6.8
McINTOSH CR M2	53 21 120 20	33	1.2	.50	92	800 .69	2.5	25 12	760	2430	3.6	2.3 5.8
McKALE R M1	53 27 120 12	31	1.1	.50	183	1600 .66	11	25 25	1380	4700	3.9	2.6 5.7
NECHAKO R RAPIDS N3	53 52 123 03	N/A	350	.50	N/A	N/A N/A	1.0	60 1.5	N/A	N/A	N/A	N/A N/A

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
NECHAKO R RAPIDS N1	53 58 123 43	N/A	200	.50	N/A	N/A N/A	0.5	25 4.0	N/A	N/A	N/A	N/A N/A
NECHAKO R RAPIDS N2	53 57 123 15	N/A	328	.50	N/A	N/A N/A	0.0	25 9.0	N/A	N/A	N/A	N/A N/A
ROBSON R R1	53 03 119 13	175	6.1	.50	61	1050 1.5	1.0	25 2.5	2690	7030	3.0	1.7 5.3
SMALL CR S1	53 04 119 35	261	9.1	.50	61	1400 1.8	5.0	25 7.0	4000	11050	3.1	1.8 5.6
SWIFTCURRENT CR S2	53 01 119 17	165	5.8	.50	61	800 1.4	2.0	25 0.5	2550	5730	2.6	1.4 4.6
UNNAMED CR U2	53 08 120 01	27	.90	.50	335	1300 .55	14	25 23	2240	4700	2.4	1.5 3.7
UNNAMED CR U3	53 21 119 51	36	1.3	.50	274	2000 .69	34	25 32	2490	9300	4.2	2.7 6.7
UNNAMED CR U1	53 10 120 02	13	.50	.50	549	1700 .41	12	25 18	1830	4440	2.8	1.8 4.4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STUDY BOUNDARY
STUDY AREA
TRANSMISSION LINES
COAST DISTRICT
RANGE 5
COAST DISTRICT
RANGE
COAST DISTRICT RANGE 5
COAST DISTRICT
RANGES
BULKLEY
TWEEDSMUIR
PRINCESS ROYAL
ISLAND
REGION 8
SCALE 1 : 1 000 000
10 5 0 10 20 30 40 50 60 70 80 90 100 Km
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K1
H2
S3
D1
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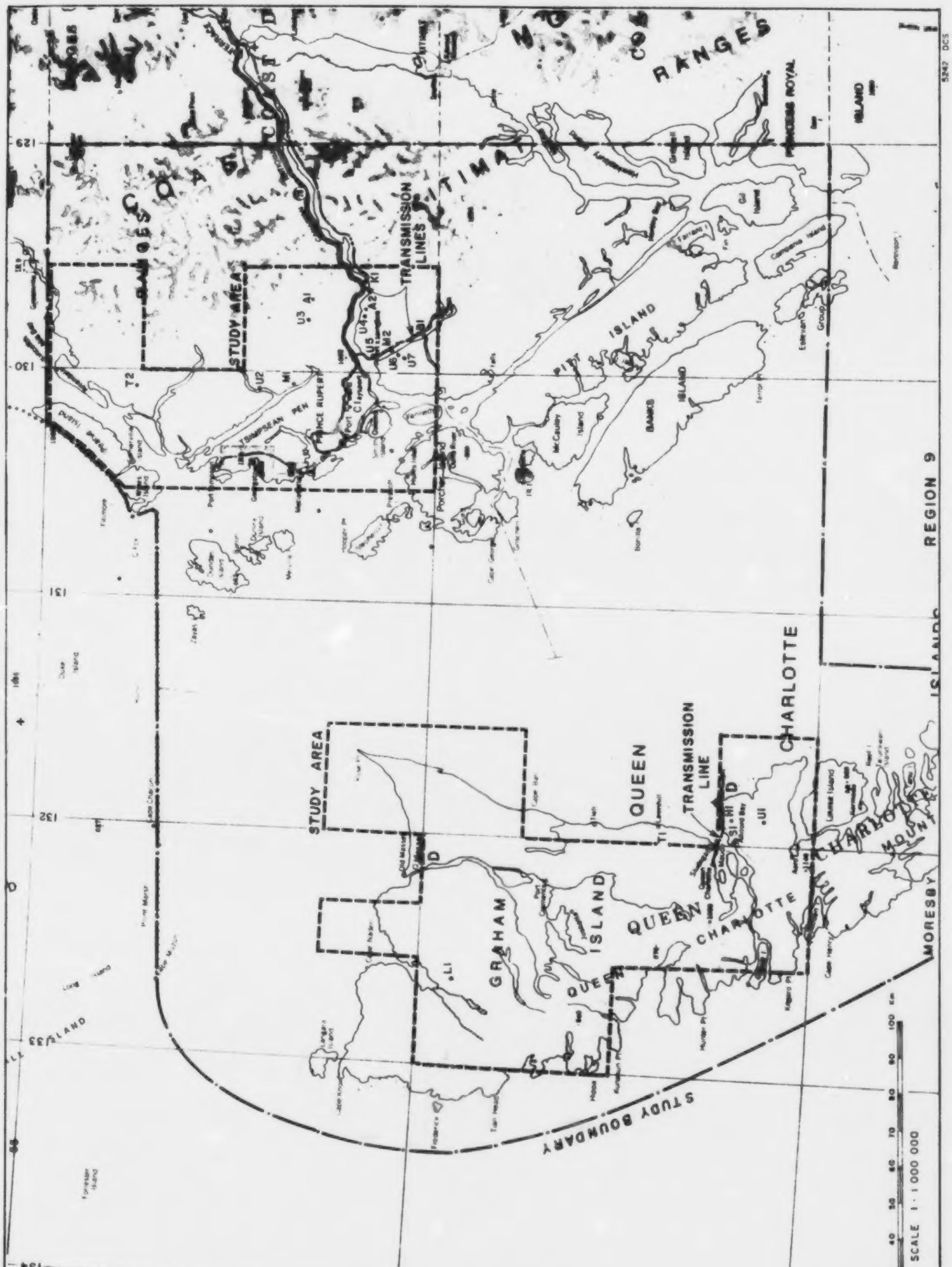
W1
U2
C2
W2
U3
C3
C4
U4
R1
S2
D2
M2
H3
B1
N1
U5
U6
A2
B3
P1
P2
Kitimat
Terrace
Houston
Burns Lake
Fort St James
Vanderhoof
Fort Fraser
Francois Lake
Old Fort
Grand Rapids
5242 DCS

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
ALICE CR A1	54 40 128 47	35	1.9	.60	92	1200 .89	2.0	138 1.0	1250	4000	3.0	1.8 5.0
ANDERSON CR A2	54 02 128 43	34	2.6	.60	61	900 1.0	1.0	25 5.0	1140	3710	3.1	1.9 5.0
BOLTON CR B1	54 13 128 26	64	4.8	.60	61	1050 1.3	8.0	25 18	2100	6600	3.0	1.8 4.9
BOWBYES CR B2	54 09 128 42	19	1.4	.60	122	800 .70	3.0	25 8.0	1230	2400	1.9	1.1 3.1
BUCK CR B3	54 20 126 37	485	3.7	.50	50	900 1.2	1.0	25 2.3	1300	4850	4.2	2.3 7.4
CHIST CR #1 C3	54 19 128 24	63	3.4	.60	31	700 1.2	12	138 13	740	5100	6.5	4.1 10
CHIST CR #2 C4	54 19 128 18	50	2.7	.60	61	975 1.0	16	138 16	1180	5900	4.7	2.9 7.6
CHIMDEMASH CR C1	54 40 128 22	82	4.5	.60	122	2500 1.3	3.0	25 0.0	3950	10400	2.5	1.6 4.0
COLDWATER CR C2	54 20 128 40	51	2.8	.60	91	1825 1.1	6.0	25 7.5	1840	7100	3.7	2.3 5.9
DAHL CR D2	54 09 128 43	32	2.4	.60	91	600 .86	1.0	25 10	1580	2700	1.6	1.0 2.7
DASQUE CR D1	54 23 128 55	68	3.7	.60	61	920 1.2	14	25 16	1600	6010	3.5	2.2 5.7
ERLANDSEN CR E1	54 36 128 44	74	4.0	.60	61	1500 1.3	1.5	25 9.0	1750	6710	3.7	2.3 5.8
GOAT CR G1	54 43 128 46	31	1.7	.60	91	675 .77	1.0	138 4.0	1120	2210	1.9	1.2 3.0
HANKIN CR H2	54 35 128 26	18	1.0	.60	91	950 .67	9.0	25 1.0	660	3100	4.4	2.7 7.3
HARDSCRABBLE CR H1	54 42 128 20	53	2.9	.60	61	350 .90	8.0	25 8.0	1270	3300	2.4	1.5 3.9

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
HOWSON CR H4	554 33 127 21	140	2.0	.50	50	700 .91	8.0	25 28	700	3900	6.2	3.1 13
HUMPHRYS CR H3	54 11 128 30	19	1.4	.60	122	1900 .82	3.0	25 13	1230	5050	3.9	2.4 6.5
KLEANZA CR K1	54 36 128 22	168	9.2	.60	92	1200 1.6	2.0	25 2.0	6060	8900	1.4	0.9 2.2
McKAY CR M2	54 13 128 25	65	4.9	.60	152	2750 1.4	8.0	25 18	5370	13100	2.3	1.4 3.8
MOLYBDENUM CR M1	54 34 128 45	19	1.0	.60	152	1100 .63	1.0	25 8.5	1090	2300	2.0	1.1 3.3
NABEELAH CR N1	54 08 128 32	19	1.4	.60	92	900 .75	2.0	25 6.0	920	2500	2.5	1.5 4.2
PINKUT CR FALLS #1 P1	54 27 125 27	862	6.0	.43	31	400 N/A	0.0	25 30	1300	4200	4.0	2.5 6.2
PINKUT CR FALLS #2 P2	54 26 125 25	862	6.0	.43	N/A	N/A N/A	0.0	25 30	N/A	N/A	N/A	N/A N/A
RALEY CR R1	54 12 128 42	19	1.5	.60	91	1250 .82	3.0	25 15	980	3900	3.7	2.3 6.0
SERB CR RAPIDS S4	54 46 127 38	155	2.2	.50	N/A	N/A N/A	4.0	25 28	N/A	N/A	N/A	N/A N/A
SHAMES R S3	54 25 128 54	78	4.3	.60	61	1320 1.3	0.0	25 15	1880	6060	3.1	1.9 4.9
SHANNON CR S2	54 40 127 30	28	1.5	.60	122	1200 .77	5.0	25 17	1300	3400	2.4	1.5 1.3
SINCLAIR CR S5	54 37 127 30	48	.70	.50	100	1500 .62	1.5	25 17	480	3000	6.9	3.7 1.3
STE CROIX S1	54 42 128 19	31	1.7	.60	122	1400 .83	1.4	25 6.0	1490	4050	2.6	1.6 4.1
TROUT CR T1	54 51 127 19	115	1.6	.60	50	500 .79	0.0	25 0.0	570	1910	3.8	1.8 7.9

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
UNNAMED CR U4	54 15 128 46	10	.70	.60	122	800 .54	7.0	25 21	610	2340	3.6	2.0 6.6
UNNAMED CR U1	54 23 128 53	26	1.4	.60	183	1250 .70	13	25 15	1800	4440	2.3	1.4 3.8
UNNAMED CR U5	54 05 128 30	13	1.0	.60	61	950 .73	4.0	25 5.0	440	2600	5.5	3.4 9.1
UNNAMED CR U3	54 19 128 24	1.2	1.2	.60	91	850 .70	8.0	138 10	790	3000	3.6	2.3 5.7
UNNAMED CR U2	54 22 128 54	41	2.2	.60	122	2100 .99	13	25 15	1900	7920	3.9	2.4 6.3
UNNAMED CR U6	54 05 128 20	34	2.6	.60	91	900 .95	15	25 22	1700	5500	3.0	1.9 4.9
WHITE CR W1	54 24 128 41	23	1.3	.60	152	1750 .75	5.0	25 8.0	1390	4020	2.7	1.7 4.3
WILLIAMS CR W2	54 24 128 25	136	7.5	.60	61	1100 1.6	4.0	25 6.0	3290	7510	2.2	1.4 3.5
ZYMOETZ R Z1	54 47 127 49	600	8.4	.50	N/A	N/A N/A	3.0	25 38	N/A	N/A	N/A	N/A N/A

COAST
MOUNTAINS
RANGES
KITIMAT
STUDY AREA
TRANSMISSION LINES
PRINCE RUPERT
TSIMPSEAN PEN
Port Edward
PITT ISLAND
BANKS ISLAND
McCauley Island
PRINCESS ROYAL ISLAND
Porcher Island
Dundas Island
Zayas Island
Dixon Entrance
STUDY AREA
TRANSMISSION LINE
GRAHAM ISLAND
QUEEN CHARLOTTE
QUEEN CHARLOTTE ISLANDS
QUEEN CHARLOTTE MOUNTAINS
MORESBY
STUDY BOUNDARY
REGION 9
Langara Island
Forrester Island
Long Island
Cape Knox
Tow Hill
Masset
Sandspit
T1
T2
U1
U2
U3
U4
U5
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U7
U11
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SCALE 1 : 1 000 000
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100 Km
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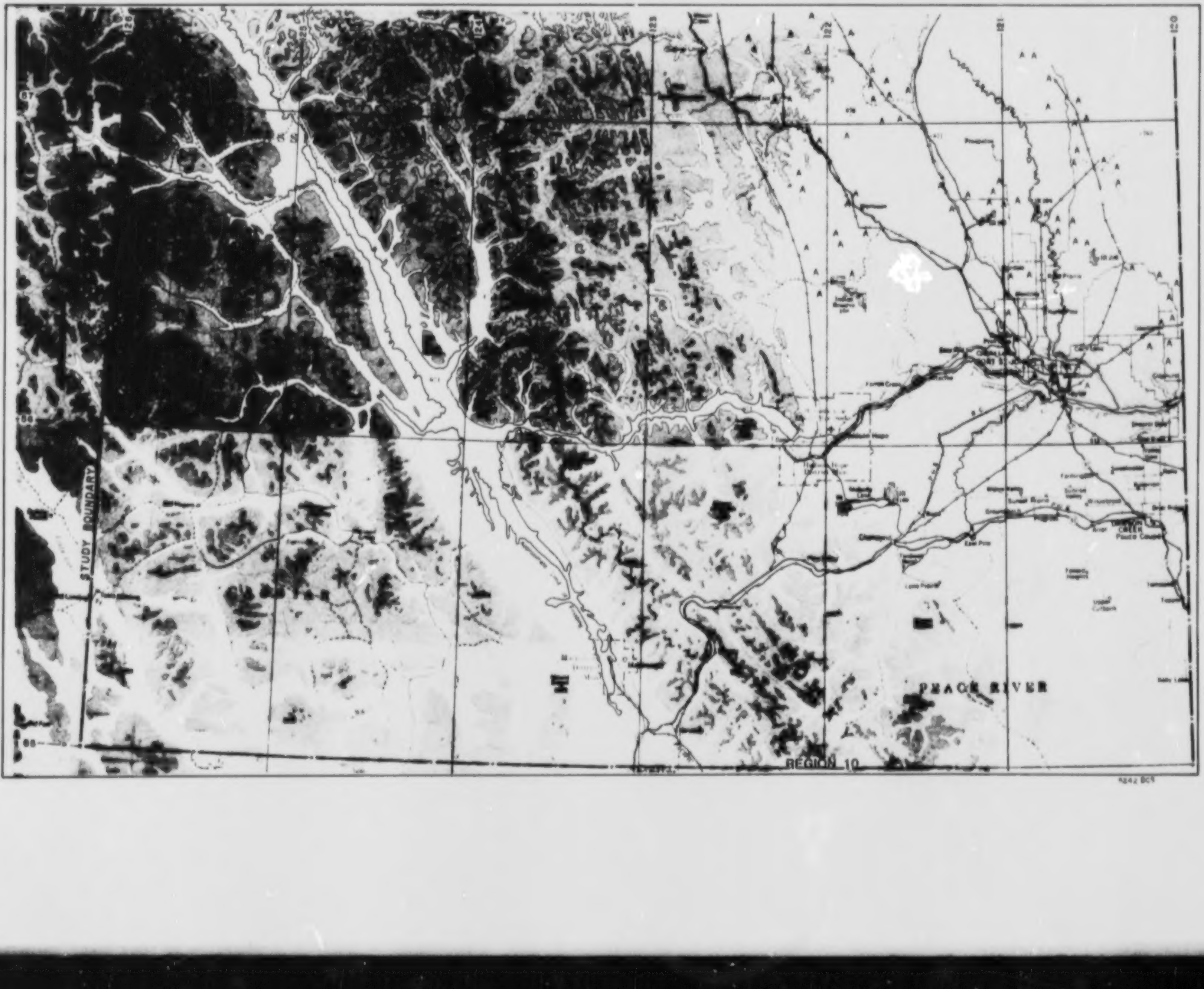
5242 DCS

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
ARDEN CR A1	54 19 129 41	12	1.2	.70	336	750 .55	15	25 16	2900	4500	1.3	0.8 2.1
AYTON CR A2	54 11 129 43	45	4.5	.70	31	400 1.2	3.0	230 6.0	1000	3830	3.1	1.7 5.8
BROWN CR B1	54 02 129 50	56	6.0	.72	107	500 1.1	1.0	69 3.0	4660	4400	0.7	0.5 1.2
COLONEL JOHNSON CR C1	54 13 130 09	3	.30	.70	276	800 .36	3.0	69 5.0	610	1530	2.0	1.1 3.8
HAANS CR SANDSPIT H1	53 13 131 53	21	1.5	.65	62	1900 .95	4.0	25 4.0	650	6600	8.9	5.3 15
KHTADA CR K1	54 11 129 36	150	15	.70	62	900 2.0	1.0	230 0.5	6690	9800	1.2	0.7 2.0
LIGNITE CR L1	53 55 132 37	67	4.7	.65	61	1000 1.3	7.0	25 35	2060	6940	3.0	1.8 4.9
MARION CR M1	54 22 130 03	10	1.0	.70	122	1600 .70	3.0	230 20	870	3610	3.4	1.8 6.3
McDONALD CR M2	54 07 129 54	12	1.2	.70	315	1900 .64	2.5	69 0.5	2600	4600	1.4	0.8 2.7
SACHS CR S1	53 12 131 58	17	1.2	.65	91	850 .70	0.0	25 5.0	780	2400	2.7	1.6 4.4
TALA HAAT CR T2	54 46 130 04	36	3.1	.65	30	300 1.0	5.0	12.5 5.0	660	3030	4.0	2.1 7.7
TLELL R T1	53 22 132 00	31	2.2	.65	30	600 1.0	14	25 14	470	4700	8.8	5.3 15
UNNAMED CR U7	54 05 129 56	38	3.8	.70	30	400 1.2	3.5	69 12	820	3460	3.4	1.9 6.1
UNNAMED CR U5	54 10 129 56	1	.10	.70	650	2000 .23	3.0	69 0.5	490	1900	3.1	1.7 5.9
UNNAMED CR U1	53 08 131 53	19	1.3	.70	30	600 .84	2.5	25 11	280	2800	8.0	4.7 13

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
UNNAMED CR U2	54 27 130 04	6	.60	.70	274	1100 .47	2.0	230 30	1180	2200	1.5	0.6 4.1
UNNAMED CR U6	54 06 129 55	56	5.6	.70	31	600 1.4	2.5	69 12	1250	5100	3.3	2.1 5.4
UNNAMED CR U3	54 20 129 46	7	.70	.70	397	800 .45	15	25 16	2000	3940	1.6	1.0 2.6
UNNAMED CR U4	54 11 129 45	15	1.5	.70	122	1300 .78	3.0	230 10	1300	3720	2.3	1.2 4.3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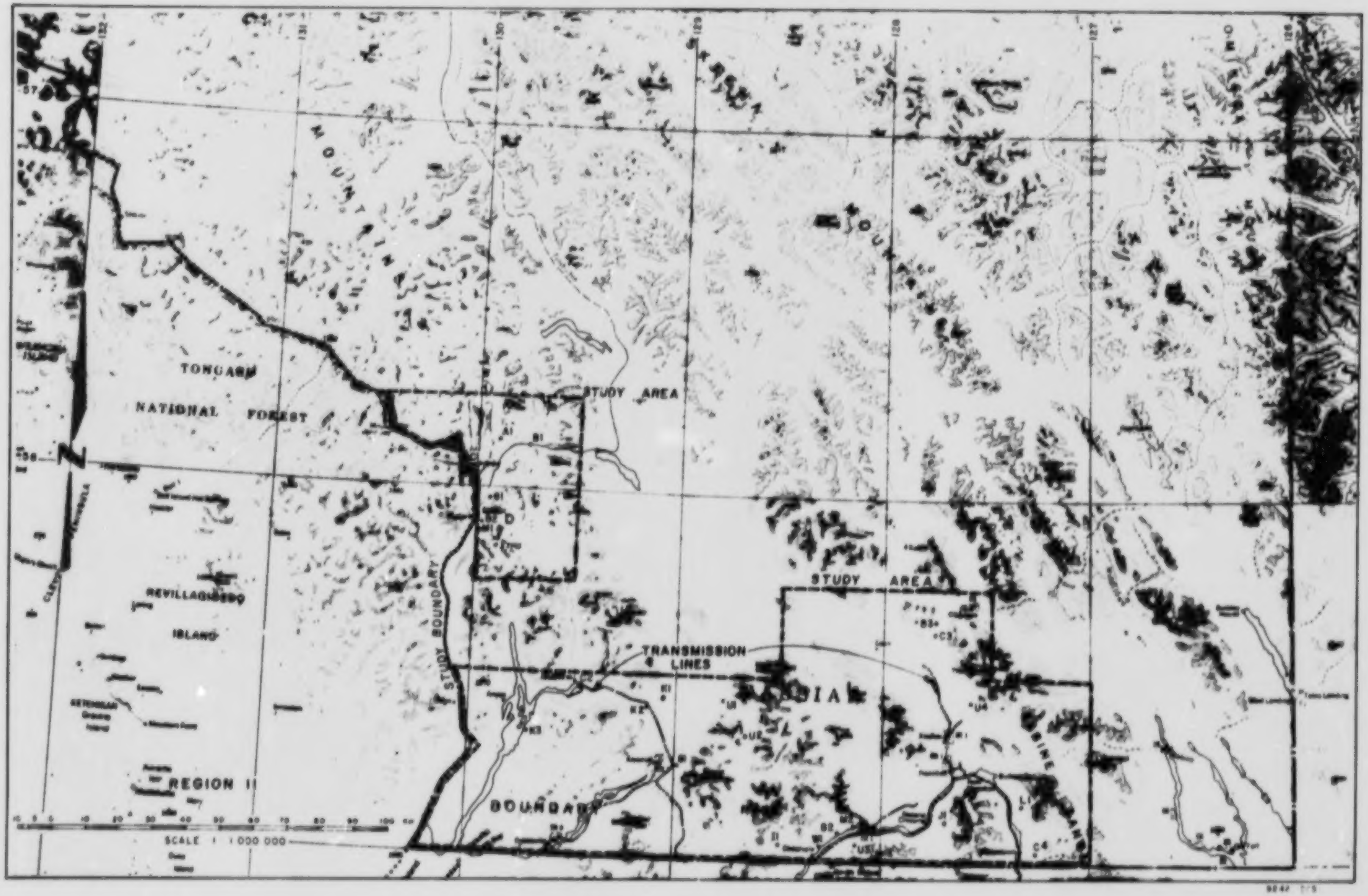
STUDY BOUNDARY
DAWSON CREEK
Pouce Coupe
PEACE RIVER
REGION 10



TONGASS
NATIONAL FOREST
STUDY AREA
STUDY AREA
STUDY BOUNDARY
TRANSMISSION LINES
REVILLAGIGEDO
ISLAND
REGION II
BOUNDARY
MOUNTAINS
SCALE 1 : 1 000 000
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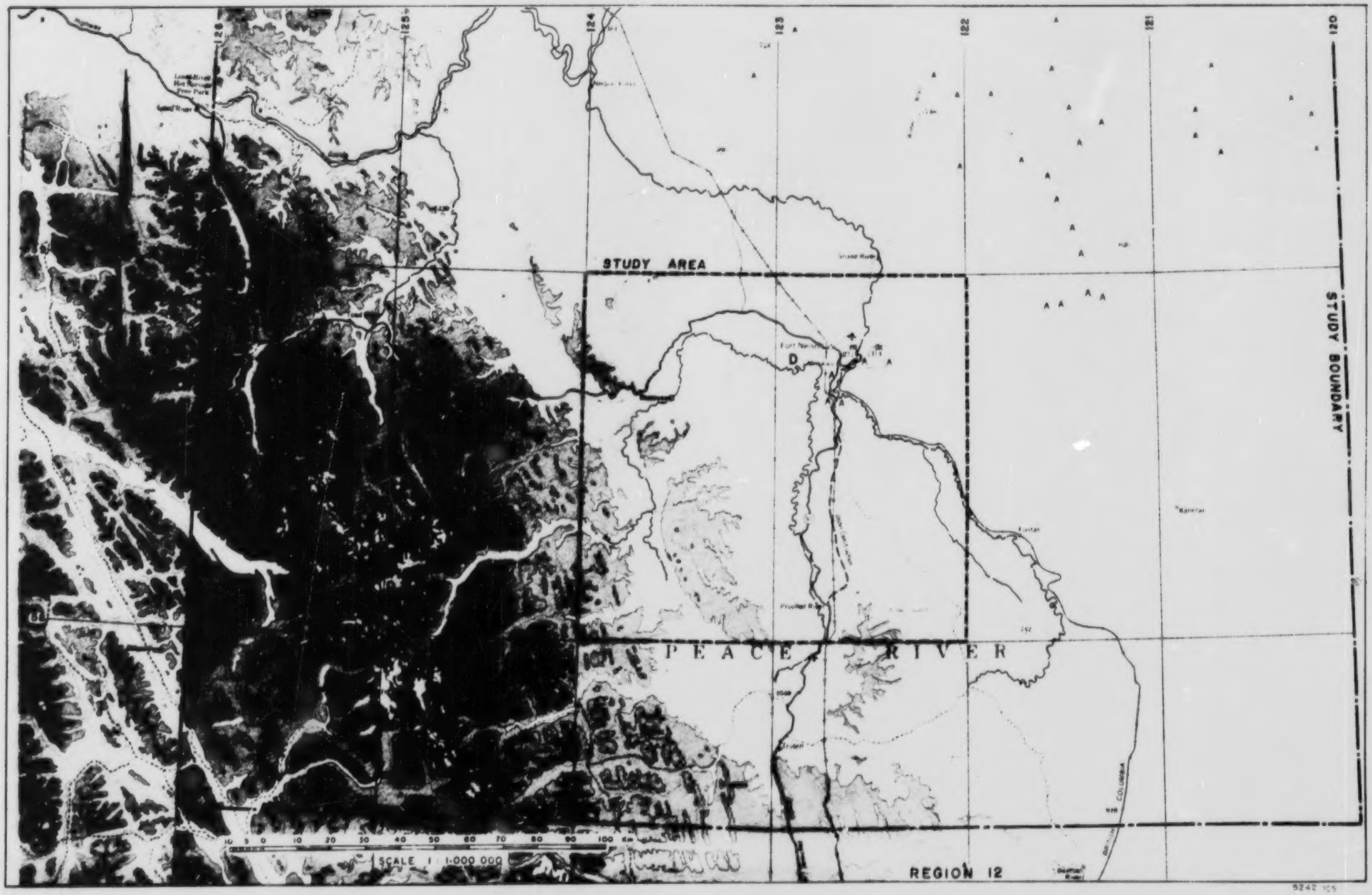
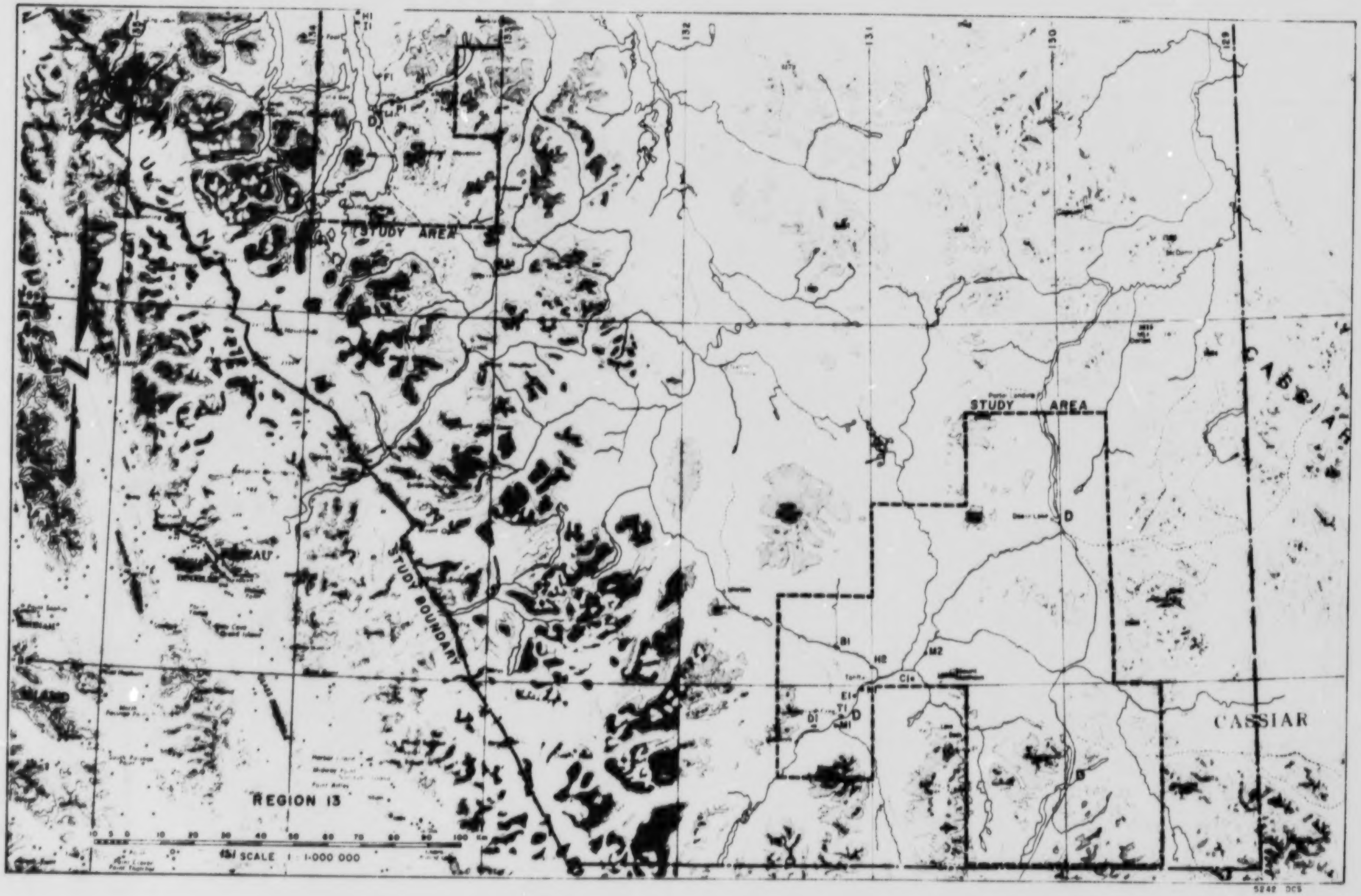
BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
AMERICAN CR A1	56 08 129 54	81	5.1	.55	91	1400 1.3	6.0	25 25	3340	8800	2.7	1.6 4.6
BARNEY GULCH B2	55 57 129 58	8	.50	.55	457	2000 .45	1.5	25 2.0	1590	3400	2.2	1.0 4.9
BEAR R B1	56 07 129 46	77	5.1	.55	30	450 1.3	0.0	25 28	1100	4100	3.9	2.5 6.0
BLACKSTOCK CR B3	55 40 127 45	40	.80	.50	92	550 .56	2.0	25 20	530	1760	3.8	1.4 10
CARRIGAN CR C3	55 38 127 45	36	.72	.50	91	650 .55	2.0	25 16	470	1830	4.4	1.7 12
CASCADE R C1	56 03 130 02	68	4.1	.55	61	350 1.0	0.5	25 17	1800	3100	1.8	0.9 3.5
CAUSQUA CR C4	55 02 127 16	52	1.0	.50	91	550 .62	3.0	25 4.5	680	1920	3.2	1.2 8.6
CLARY CR C2	55 28 129 27	33	2.0	.65	488	2050 .73	6.0	25 3.0	6950	9600	1.2	0.6 2.3
GLACIER CR G1	55 59 129 56	49	2.9	.55	61	600 .99	2.0	25 7.0	1270	3620	3.0	1.5 5.9
INSECT CR I1	55 03 128 29	32	1.3	.60	152	2550 .81	16	25 13	1430	8730	5.8	2.8 12
JUNIPER CR J1	55 07 127 42	60	1.2	.60	91	1550 .79	10	25 8.0	780	4840	7.0	2.6 19
KELSKIIST CR K3	55 21 129 42	53	3.4	.60	183	1550 1.0	2.0	25 28	4500	6900	1.5	0.8 2.7
KSHADIN CR K1	55 27 129 03	50	3.0	.60	92	1150 1.1	18	69 6.0	1980	7600	3.6	1.9 7.0
KWINATAHL R K2	55 25 129 08	113	6.8	.60	123	1300 1.4	15	69 1.0	6000	10400	1.6	0.9 3.2
LUND CR L1	55 10 127 20	27	.54	.50	153	1000 .49	5.0	25 16	590	2400	4.5	1.7 12

BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
MARMOT R M1	55 53 130 00	94	5.6	.55	61	650 1.3	0.7	25 7.0	2460	5200	2.2	1.1 4.3
MILL CR M2	55 06 128 07	86	3.4	.60	61	1125 1.2	1.0	25 3.0	1490	5550	3.5	1.7 7.4
SEASKINNISH CR S1	55 16 128 59	34	2.4	.60	136	1750 .97	3.0	25 2.0	2330	6850	2.8	1.5 5.1
SEDAN CR S2	55 05 128 12	116	4.6	.60	61	850 1.3	2.0	25 8.0	2030	5230	2.4	1.2 5.1
UNNAMED CR U2	55 21 128 40	42	1.7	.50	183	1750 .80	20	25 30	2200	8030	4.1	2.0 8.4
UNNAMED CR U3	55 03 128 07	65	2.6	.60	61	950 1.0	5.0	25 3.3	1140	4800	4.0	1.9 8.4
UNNAMED CR U1	55 26 128 46	45	.90	.50	152	1050 .59	6.0	25 16	980	3100	3.6	1.8 7
UTSUN CR U4	55 27 127 35	37	.74	.50	122	1450 .61	2.0	25 5.0	650	2900	5.1	1.9 13
WILSON CR W1	55 03 128 17	27	1.1	.60	122	1525 .71	2.0	25 5.0	950	3500	3.5	1.7 7.2


STUDY BOUNDARY
STUDY AREA
PEACE RIVER
REGION 12
120
121
122
123
124
125
126
Fort Nelson
D
Liard River Hot Springs Prov Park
Fontas
BRITISH COLUMBIA
SCALE 1 : 1 000 000
10 5 0 10 20 30 40 50 60 70 80 90 100 Km
5242 ICS


CASSIAR
CASSIAR
STUDY AREA
STUDY AREA
STUDY BOUNDARY
REGION 13
129
130
131
132
D
D
D
D
B1
H2
M2
C1
E1
T1
M1
D1
F1
P1
H1
I1
10 5 0 10 20 30 40 50 60 70 80 90 100 Km
SCALE 1 : 1·000 000

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BC SMALL HYDRO ASSESSMENT	LAT. LONG.	BASIN SIZE	DESIGN FLOW	FRAC. FIRM.	HEAD	PEN. LEN. DIA.	ACCESS ROAD	LINE kv/D	INST. CAP.	COST ($1000)	COST ¢/kWh	COST RANGE
BEATTY CR B1	58 06 131 11	393	3.9	.45	92	1370 1.2	19	25 17	2580	9500	4.7	2.5 8.6
CLASSY CR C1	58 01 130 47	84	.84	.45	152	900 .57	7.0	25 17	920	2950	4.1	2.2 7.5
DODJATIN CR D1	57 53 131 18	78	.78	.45	122	750 .55	3.0	25 12	680	2010	3.7	2.0 6.9
EIGHT MILE CR E1	57 58 131 05	27	.27	.45	91	150 .31	3.0	25 10	180	732	5.2	2.8 9.5
FOURTH OF JULY CR F1	59 40 133 39	178	1.8	.30	92	1600 .92	4.0	25 8.0	1180	5760	9.3	2.7 32
HARTZ CR H2	58 03 131 00	33	.33	.45	213	1600 .45	6.0	25 9.0	520	2990	7.3	3.9 14
HITCHCOCK CR H1	59 55 133 48	175	1.8	.30	62	1025 .90	2.0	25 40	780	4200	10	3.0 35
INDIAN CR I1	59 49 133 47	160	.16	.30	30	275 .78	2.0	25 32	340	1700	9.3	2.7 32
MEEHAUS CR M2	58 05 130 43	97	.97	.45	92	670 .62	8.0	25 20	640	2800	5.5	2.9 10
MESS CR M1	57 53 131 12	2350	24	.45	61	1600 2.6	7.0	25 3.0	10300	25630	3.2	1.7 5.9
NINE MILE CR N1	57 59 131 02	20	.20	.45	213	950 .36	1.0	25 13	320	1300	5.2	2.8 9.7
PINE CR DITCH P1	59 35 133 35	450	4.5	.30	61	700 1.2	2.0	25 0.5	1970	4610	4.4	2.4 8.1
TELEGRAPH CR T1	57 54 131 10	56	.56	.45	152	1200 .51	0.0	25 0.0	610	2050	4.2	2.8 6.3

APPENDIX 2

EXAMPLES OF SITE EVALUATION PROCEDURES

APPENDIX 2

CONTENTS

- SMALL HYDRO POWER EVALUATION PROCEDURE
- EXAMPLE OF SMALL HYDRO POWER SITE

FIGURE

2.1 PENSTOCK SIZING AND COMPONENT COSTING
2.2 ACCESS ROAD COSTS
2.3 GENERATING EQUIPMENT COSTS
2.4 SWITCHYARD COSTS

SMALL HYDRO POWER EVALUATION PROCEDURE

This procedure deals with the case where a prospective power developer wants to establish whether there is a feasible small hydro power site within a reasonable distance (less than 80 kilometres) and sufficiently close to a power distribution line.

The first approach would be to refer to the Resource Map and the corresponding Table in Appendix 1, and determine if there is a suitable site already identified by this study. If there is a suitable site, the next step would be to arrange for the necessary professional services to carry out a site investigation and a pre-investment study.

Alternatively the area could be investigated to locate a site with a smaller installed capacity than covered in the inventory, or a site not documented by this office study (such as a waterfall of uncertain height, or a site with relatively small capacity). Then the procedure would be as follows:

1. Obtain the 1:50,000 (or 1: 100,000) scale topographic maps of the area and plot the sites documented in this report, for reference.

2. Study the map for potential small hydro power sites and/or make a reconnaissance in the area of interest.

   A potential site will be located on a steep part of a stream (generally 5 percent slope or more); and fed by a drainage area large enough to provide adequate flow, preferably with storage (lakes or marshes).

   The nearby power distribution line must be rated at 25 kV or less if the required installed capacity is less than 100 kW.

   Generally, select a section of creek which has the steepest possible slope but which is also far enough downstream that the water intake can catch a significant amount of the basin flow.

3. Select an intake and powerhouse site, and from the map measure the following parameters:

   - the drainage area upstream of the water intake;
   - the distance to the nearest distribution line, measured along workable terrain;
   - the access road length;
   - the gross head (the vertical drop from intake to powerhouse);
   - the penstock length and slope.

4. Evaluate the hydrology (see Appendix 5):

   Refer to Figure 5.1 and note the rainfall zone which includes the drainage basin, and compare it with the rainfall zone of the nearest gauged basin.

   Adjust the mean annual runoff ($l/sec/km^2$) of the gauged basin (Figure 5.2) by the ratio of the mean rainfall of the two basins.

   Multiply the basin area (km^2) by the adjusted mean annual runoff to obtain the design mean annual flow in the basin (l/sec). Convert to m^3/s. This result is determined from the following equation:

$$\frac{\text{(Rainfall at site)}}{\text{(Rainfall at gauged basin)}} \times \text{Mean Runoff (gauged basin)} \times \frac{\text{Basin Area}}{1{,}000} = \text{Design Flow } (m^3/s)$$

   Look up the firmness factor from Figure 5.3.

5. Determine the installed capacity by multiplying the flow times the head times a constant. The constant accounts for head losses, machine efficiency and a conversion factor:

$$\text{Flow } (m^3/s) \times \text{Gross Head } (m) \times 7.0 = \text{Installed Capacity } (kW)$$

6. Evaluate the energy potential by multiplying the installed capacity times 8760 hours/year times the Firmness Factor. The firmness factor is based on the annual flow duration curves for streams in the area and it accounts for the periods when the plant cannot generate at full capacity.

$$\text{Installed Capacity } (kW) \times 8760 \text{ (hrs/yr)}$$
$$\times \text{ Firmness Factor} = \text{Energy Potential } (kW.h/yr))$$

7. Determine the penstock diameter.

$$\underset{(m)}{\text{Penstock Diameter}} = .58\sqrt{\text{Design Flow } (m^3/s)}$$

This provides a conservative penstock diameter which can be optimized in final design.

8. **Determine the Total Project Cost**

Follow the procedure outlined in Figure 2.1 to determine Penstock, Intake and Powerhouse costs. Subtotal 1 is the sum of these costs.

Penstock Cost	See Figure 2.1	$
Intake Cost	See Figure 2.1	
Powerhouse Cost	See Figure 2.1	__________
	Subtotal 1	**$**

Multiply Sub Total 1 by Site Factor:

Site near a large city	1.0
Site near a town	1.2
Site near a village	1.3
Site isolated, no road transport	1.5

Generating Equipment Cost — See Figure 2.3

Assume Turbine Effective Net Head
is 90 percent of the Gross Head

Access Road Cost — See Figure 2.2 ________

Subtotal 2 $

Subtotal 2 is the sum of Subtotal 1 times the Site Factor, plus Generating Equipment Cost and Access Road Cost.

Allowance for Engineering of 20% of Subtotal 2

Apply Contingency Factor of about 30% of Subtotal 2 ________

Subtotal 3 is the sum of Subtotal 2, Engineering Allowance and Contingency Costs.

Sub Total 3 $

Transmission Line Cost — See Figure 3.8 ________
See notes added to Figure 3.8

Total Project Cost is the sum of Subtotal 3 and the Transmission Line Cost.

TOTAL PROJECT COST $

9. Revenue Estimate

Choose the applicable Net Rate of Payment from the following Table (B C Hydro, April 1, 1982). Consult B C Hydro for current rates.

- For capacities OVER 35 kW - General

Trailing step rate	2.197	
less water tax	.314	
Net to Producer	1.883	¢/kW.h

- For capacities UNDER 35 kW - General

Trailing step rate	3.424	
less water tax	.314	
Net to Producer	3.110	¢/kW.h

- For capacities under 35 kW - RESIDENTIAL

Trailing step rate	3.758	
less water tax	.314	
Net to Producer	3.444	¢/kW.h

Gross Revenue = Net rate of payment x Energy Potential (kW.h)

Net Revenue = Gross Revenue less the following:

1. Revenue lost to Maintenance and Repair (allow 10% for the times plant is shut down).
2. Routine Maintenance and Operation (about 1.0% of capital cost but some installations could have costs as high as 2 - 4% with full time attendance at a small site).

Convert the Net Revenue to a percentage of Capital Cost and evaluate the project economics.

Example of Small Hydro Power Site

As an example of the procedure the following site has been analysed:

Creek Name:	Zeballos (Little) River	
Location:	Latitude 49° 59' Longitude 126° 45'	
Powerhouse Elevation:	304 m	
Intake Elevation:	514 m	
Gross Head: Intake Elevation - Powerhouse Elevation:	210 m	
Horizontal Penstock Length:	750 m	
Basin Area:	9 km^2	
Access Road:	0.4 km	
Distance to nearest transmission line	6 km	
Rating of transmission line:	25 kV	
Rainfall in Zeballos (Little) River Basin:	150 inches/year	**Figure 5.1**
Rainfall in adjacent gauged basin:	150 inches/year	**Figure 5.1**
Runoff in adjacent gauged basin	168 litres/sec/km^2	**Figure 5.2**

Calculated Mean Annual Flow:

$$\frac{150 \text{ inches/year}}{150 \text{ inches/year}} \times 168 \text{ litres/sec/km}^2 \times \frac{9 \text{ km}^2}{1000} = 1.5 \text{ m}^3\text{/sec}$$

Firmness Factor (Figure 5.3) 65% or 0.65

Installed Capacity:

$$1.5 \text{ m}^3\text{/sec} \times 210 \text{ m} \times 7.0 = 2200 \text{ kW}$$

Energy Potential:

(2200 kW) (8760 hrs) (0.65) = 12,530,000 kW.h

Penstock Radius:

$0.29\sqrt{1.5} = 0.36$ m

In the example for the Little Zeballos River, the calculations are as follows:

a) Penstock Cost - (Empirical Method)

1. Vertical Drop H = 210 m

   Horizontal Length l = 750 m

   Actual Penstock Length $L = \sqrt{H^2 + l^2}$

   $L = \sqrt{(210)^2 + (750)^2}$ = 780 m

   Design Flow Q = 1.5 m^3/s

2. $HMIN = 90/\sqrt{Q}$ (Vertical distance below intake at which penstock goes beyond minimum thickness)

   $HMIN = 90/\sqrt{1.5} = 73.5$ m

   HMIN IS LESS THAN H

3. CALCULATE t (See simplified method following page)

   (i) Calculate T (Maximum thickness)

   $$T = 4.7 \times 10^{-5} \times H \times \sqrt{Q}$$

   $$T = 4.7 \times 10^{-5} \times 210 \times \sqrt{1.5} = 0.0121 \text{ m}$$

   (ii) Calculate t (Average thickness)

   $$t = \frac{HMIN}{H} \times 0.0064 + \left(\frac{H - HMIN}{H}\right)\left(\frac{T + 0.0064}{2}\right)$$

   $$t = \frac{73.5}{210} \times 0.0064 + \left(\frac{210 - 73.5}{210}\right)\left(\frac{0.0064 + 0.0121}{2}\right) = 0.0082 \text{ m}$$

4. CALCULATE THE WEIGHT OF THE PENSTOCK

   $$W = t\,(2\pi R)\,(7860)L$$

   $$W = 0.0082\,(\pi)\,(0.71)\,(7860)\,(780) = 112{,}000 \text{ kg}$$

SIMPLIFIED METHOD FOR CALCULATING PENSTOCK WEIGHT

1. Let H = Vertical drop of penstock

   L = Actual Length of Penstock

   Q = Design Flow

2. HMIN $= 90/\sqrt{Q}$ m **Assuming F S = 1.5 (Factor of Safety)**
   tMIN = 0.00635

3. If HMIN larger than H, then $t = 0.0064$ m

   If HMIN smaller than H:

   1. CALCULATE T

      $$T_{(m)} = 4.7 \times 10^{-5} \times H \times \sqrt{Q}$$

   2. CALCULATE t

      $$t_{(m)} = \frac{HMIN}{H} \times 0.0064 + \left(\frac{H - HMIN}{H}\right)\left(\frac{T + 0.0064}{2}\right)$$

4. CALCULATE WEIGHT W

   $$W_{(kg)} = t \times 2\pi R \times 7860 \times L$$

Approximate Cost of penstock

= (112,000) x (slope factor) x (installation factor) x $^{\$1}/\mathrm{Kg}$

where slope factor = 1.13 **(See Fig 2.1)**

Installation factor = 4.7 **(See Fig 2.1)**

Approximate Penstock Cost = 112,000 kg x(1.13) (4.7) ($1/kg) = $595,000

b) **Intake Cost** **(Empirical Method)**

Intake cost = $20,000 + 50,000 (Design Flow in m^3)

Intake cost = $20,000 + 50,000 (1.5) = $100,000 (See Fig 2.1)
($20,000 is an assumed fixed cost)

c) **Powerhouse Cost (Empirical Method)** **(See Fig 2.1)**

First select an appropriate turbine from Figure 3.2

1. $P(hp) = Q\,(cfs) \times h(ft) \times 0.1 = (1.5\ m^3/sec)\ \frac{(35.3\ ft^3/sec)}{m^3/sec}\ (210\ m)\ \frac{(3.28ft)}{m}\ (0.1) = 3650\ hp$

(Definitions are shown on Figure 3.2)

2. Try N = 1200 rpm **(most efficient operating speed)**

$$Ns = \frac{1200\sqrt{3650}}{((210)(3.28))^{1.25}} = 20.5 \text{ (specific speed)}$$

3. From Chart A, this means that a Francis turbine will be selected.
With a gross head of 210 m (689 feet) and zero draft head, Chart B recommends that the specific speed Ns be no greater than about 30

Therefore: A Francis turbine with a speed of 1200 rpm is OK
Note that this range is also suitable for a Turgo Impulse Wheel (see Table 2.1)

4. $Z_1 = 33.1 - (\sigma_c \times H) =$ Maximum Turbine Elevation above tailwater (to prevent cavitation in Francis or Propeller turbines. See Section 2.3 and Fig 3.2).

Where σ_c is about .025 from Chart C (Figure 3.2)
$z_1 = 15.8$ feet - Therefore OK

5. Turbine runner diameter

$$D\,(Ft) = \frac{153.3 \quad 689}{1200}(0.75) = 2.5 \text{ ft} = .75 \text{ m}$$

Power house dimensions are as follows:

Length of Powerhouse = 3.6 m + 11 (.75 m) = 11.9 m

Width of Powerhouse = 2.1 m + 6.5 (.75 m) + 4 (.8 m) = 10.2 m

	Powerhouse Cost = ($2400/$m^2$) (10.2 m) (11.9 m)		$ 291,000
	SUB TOTAL 1		**1,000,000**
	Site Factor (1.4) x Sub Total 1		**$ 1,400,000**
d)	**Generating Equipment Cost**	**(See Fig 2.3)**	
	Generating Equipment Cost		$ 500,000
e)	**Access Road Cost**	**(See Fig 2.2)**	
	Access Road Cost = ($84,000/km) (0.4 km)		$ 34,000
	SUB TOTAL 2		$ 1,934,000
	Allowance for Engineering 20%		387,000
	Apply a Contingency Factor of about 30%		$ 580,000
	SUB TOTAL 3		**$ 2,900,000**
f)	**Transmission Line Cost**	**(See Fig 3.8)**	
	25 kV line will be required		
	Therefore:		
	Transmission Line Cost = (6 km) $\frac{(\$50,000)}{\text{km}}$		$ 300,000
	TOTAL PROJECT COST		**$ 3,200,000**

Revenue Estimate

Net Water Revenue/year = (12,530,000) x (0.01883)	= $ 236,000
Percentage of Capital Cost	7.38%
Interest Rate: Assume	13%
Assumed Energy Inflation Rate	8%

Recommendation for Further Work:

- Conduct economic study
- Apply for land rights
- Perform preliminary engineering
- Apply for water rights
- Negotiate with B C Hydro
- Final design
- Order turbine
- Issue construction contract
- Commission plant

STANDARD STEEL SIZES

DIAMETER IN		m	WALL THICKNESS min. IN.	min. mm	max. IN.	max. mm
6	(ID)	0.152	0.125	3.2	0.432	11.0
8	↓	0.203	0.156	4.0	0.500	12.7
10	↓	0.254	0.203	5.2	↓	↓
12	↓	0.308	0.203	5.2	↓	↓
16	↓	0.406	0.219	5.6	↓	↓
18	(OD)	0.457	0.250	6.4	↓	↓
↓	↓		↓	↓	↓	↓
30	↓	0.762	0.250	6.4	0.500	12.7
36	↓	0.914	0.312	7.9	0.562	14.3
↓	↓		↓	↓	↓	↓
80	↓	2.03	0.312	7.9	0.562	14.3

NOTE: ID = INTERIOR DIAMETER
OD = EXTERIOR DIAMETER
MINIMUM ALLOWABLE THICKNESS = .00624m

CHART A

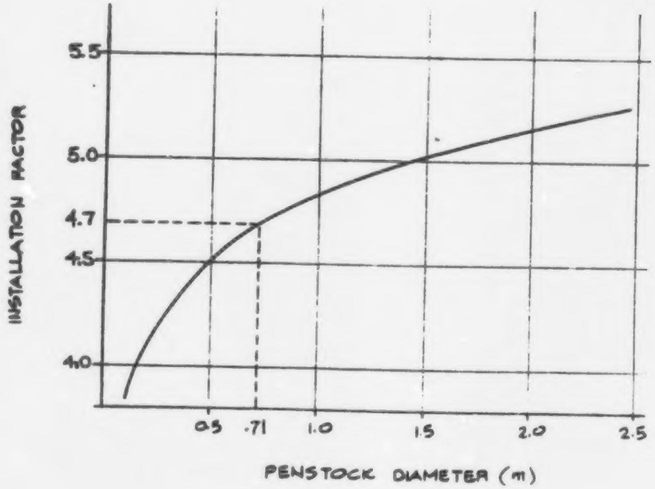

CHART B

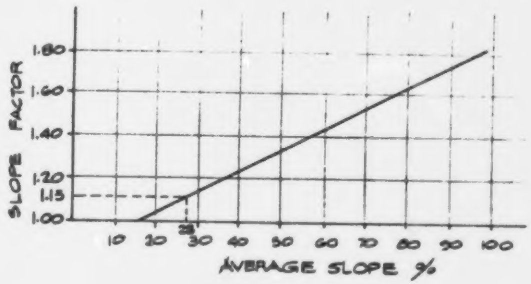

CHART C

POWERHOUSE AREA

1. CALCULATE RUNNER DIAMETER D FROM FIGURE 3.2 CONVERT TO METRES.
2. FOR A PELTON WHEEL

   $L(m) = 3.6m + 7 \times D(m)$

   $W(m) = 2.1m + 3.5 \times D + 4 \times 2R\ (m)$

   $AREA\ (m^2) = L \times W$
3. FOR A FRANCIS TURBINE (HORIZONTAL)

   $L(m) = 3.6m + 11 \times D$

   $W(m) = 2.1m + 6.5D + 4 \times 2R\ (m)$

   $AREA\ (m^2) = L \times W$
4. PROPELLER TURBINE

   THE POWERHOUSE SIZE DEPENDS ON WHETHER THE TURBINE IS HORIZONTAL OR VERTICAL, AS WELL AS ON SITE CONDITIONS. CONSULT A MANUFACTURER TO DETERMINE THE OUTSIDE DIMENSIONS OF THE TURBINE/GENERATOR ASSEMBLY, AND ADD ABOUT 3.0 m TO EACH DIMENSION TO APPROXIMATE THE BUILDING SIZE.

CHART D

COST EVALUATION PROCEDURE
(BASED ON STEEL PENSTOCKS)

1. CALCULATE PENSTOCK RADIUS R

   $R(m) = 0.29\sqrt{FLOW\ (m^3/s)}$

   PENSTOCK DIAMETER = 2 × R
   DIVIDE PIPE INTO PRESSURE ZONES FOR ECONOMY
2. CALCULATE MAXIMUM THICKNESS T (m)

   $T = 4.7 \times 10^{-5} \times GROSS\ HEAD\ (m) \times \sqrt{FLOW\ (m^3/s)}$

   CHOOSE A STANDARD THICKNESS FROM CHART A.
3. CALCULATE THE WEIGHT OF PIPE

   $W = T \times 2\pi R \times 7860\ kg/m^3 \times LENGTH\ (m)$

   (FOR EACH PRESSURE ZONE)
4. DETERMINE INSTALLATION FACTOR (I.F.) (CHART B)
5. DETERMINE SLOPE FACTOR (S.F.) (CHART C)
6. $PENSTOCK\ COST = W \times \$\frac{1.0}{kg} \times I.F. \times S.F.$
7. INTAKE COST = $20,000 + 50,000 × FLOW (m³/s)
8. SELECT AN APPROPRIATE TURBINE USING FIG. 3.2
9. POWERHOUSE COST = $2400 × AREA (m²)
   DETERMINE AREA FROM CHART D

PENSTOCK SIZING AND COMPONENT COSTING

FIGURE 2.1

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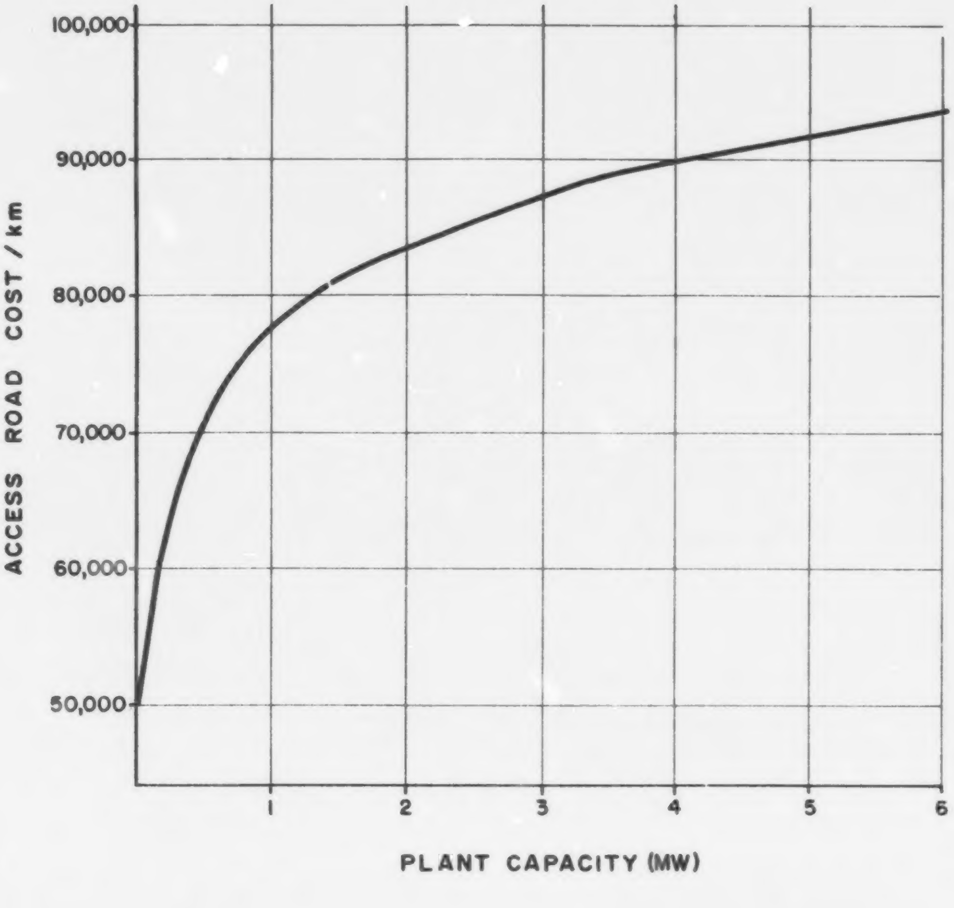
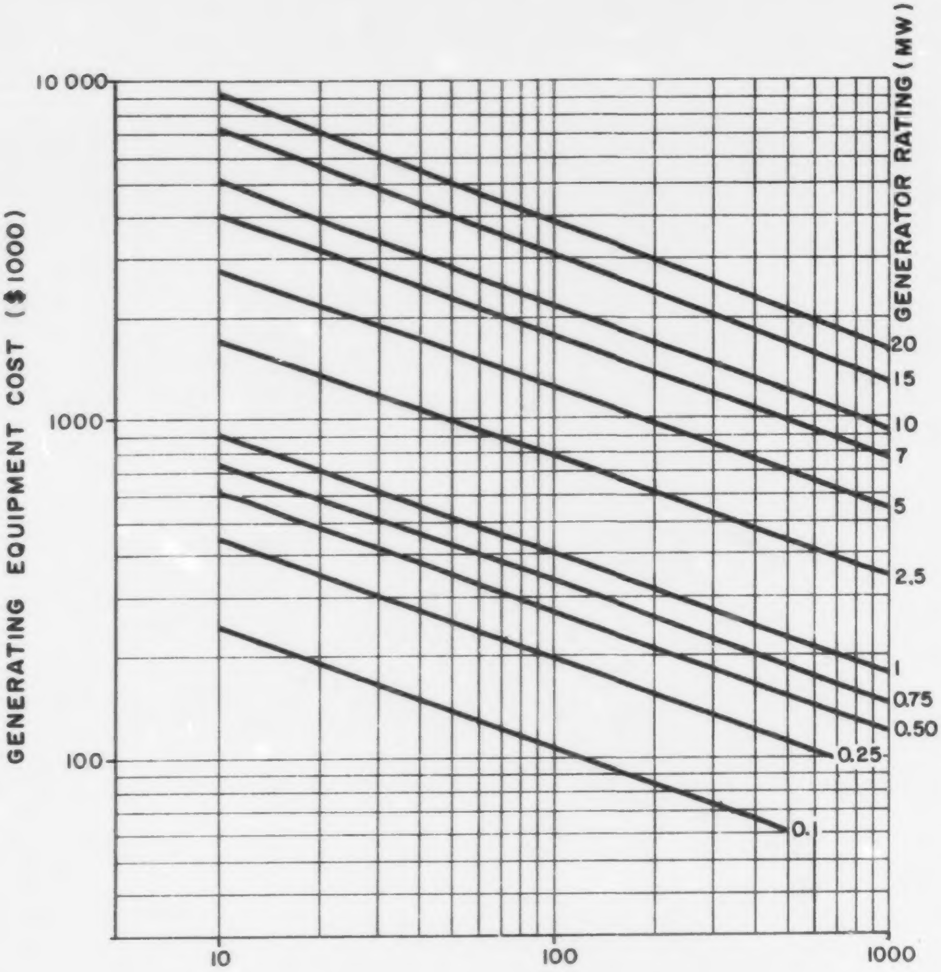


FIGURE 2·2

DCS 5242



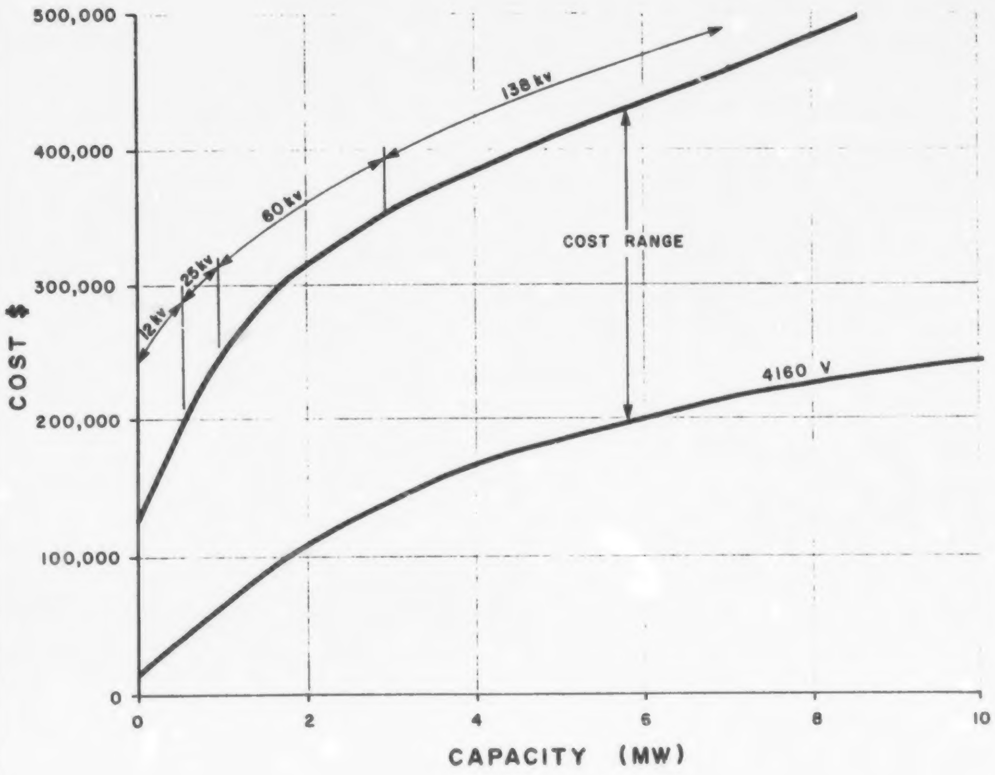
NOTES:

1. Cost base March 1982
2. Costs can vary ± 30% depending on the turbine type and prevailing market conditions.

GENERATING EQUIPMENT COSTS

FIGURE 2·3

5242 DCS



1. Upper cost limit is for a low voltage generator and a line voltage as shown.

2. Lower cost limit is for a generator and line voltage the same.

3. Costs include switchyard (transformers, circuit breaker, disconnect switch, potential transformers, lightning arrestors), civilworks, and utility interconnection charge.

4. Based on Tudor Engineering, 1978.

SWITCHYARD COSTS

FIGURE 2-4

DCS

APPENDIX 3

MANUFACTURERS INFORMATION
SPECIFICATIONS AND SYSTEM DIAGRAMS

APPENDIX 3

CONTENTS

FIGURE

3.1 SMALL HYDRO POWER SYSTEM DIAGRAM

3.2 TURBINE APPLICATION CHART

3.3 GOVERNOR SYSTEMS

3.4 TYPICAL PROTECTION SYSTEM

3.5.1 PENSTOCK COST DATA

3.5.2 PENSTOCK APPLICATION CHART

3.6 INTAKE DETAILS

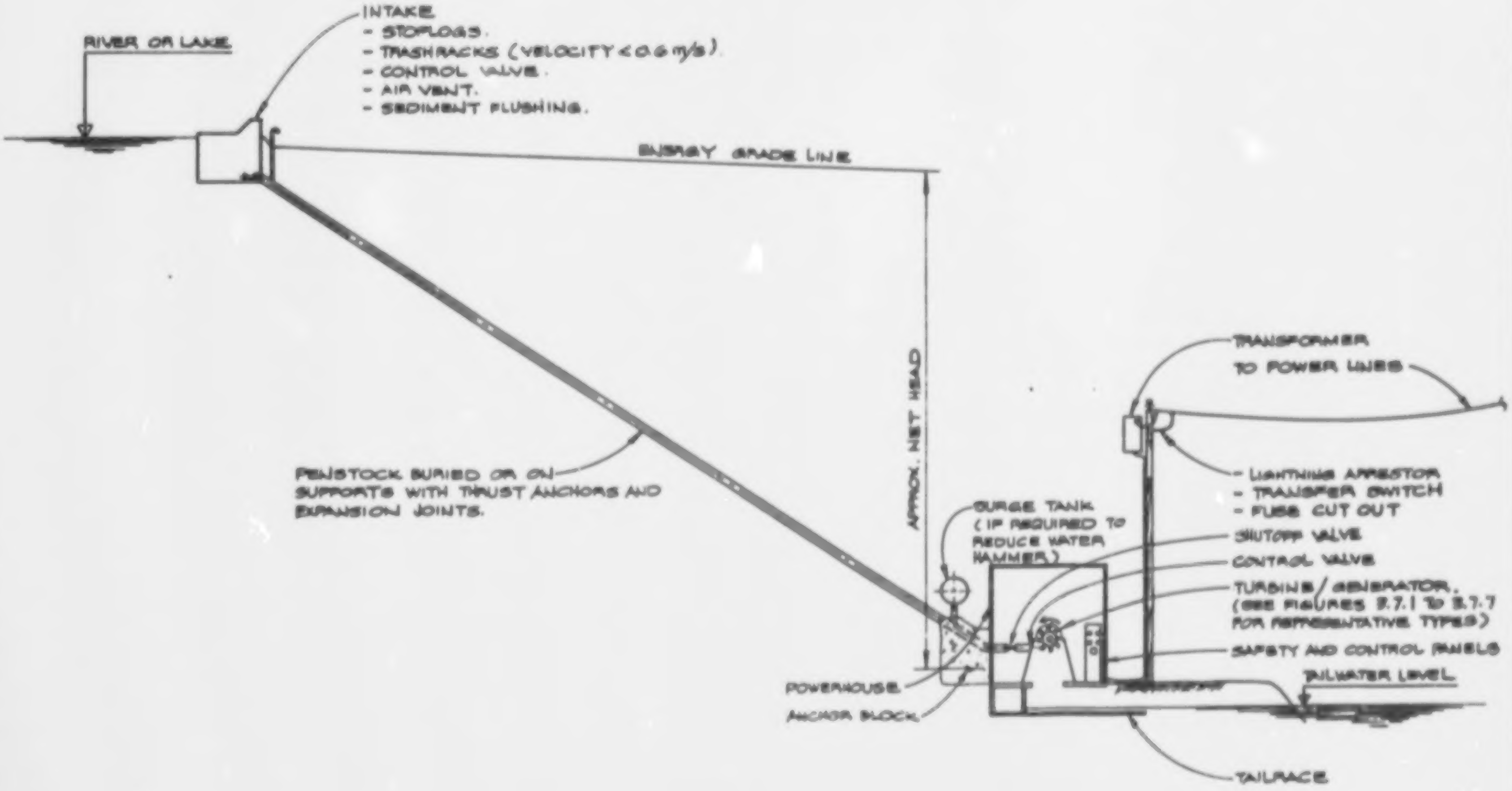
3.7.1 POWERHOUSE LAYOUT 1
3.7.2 2
3.7.3 3
3.7.4 4
3.7.5 5
3.7.6 6
3.7.7 7

3.8 TRANSMISSION LINE SIZING

LIST OF EQUIPMENT SUPPLIERS

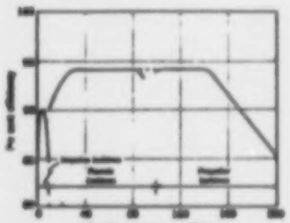
TURBINE DATA SHEET

GENERATOR DATA SHEET


RIVER OR LAKE
INTAKE
- STOPLOGS.
- TRASHRACKS (VELOCITY < 0.6 m/s).
- CONTROL VALVE.
- AIR VENT.
- SEDIMENT FLUSHING.
ENERGY GRADE LINE
PENSTOCK BURIED OR ON SUPPORTS WITH THRUST ANCHORS AND EXPANSION JOINTS.
APPROX. NET HEAD
SURGE TANK (IF REQUIRED TO REDUCE WATER HAMMER.)
POWERHOUSE
ANCHOR BLOCK
TRANSFORMER
TO POWER LINES
- LIGHTNING ARRESTOR
- TRANSFER SWITCH
- FUSE CUT OUT
SHUTOFF VALVE
CONTROL VALVE
TURBINE / GENERATOR. (SEE FIGURES 3.7.1 TO 3.7.7 FOR REPRESENTATIVE TYPES)
SAFETY AND CONTROL PANELS
TAILWATER LEVEL
TAILRACE

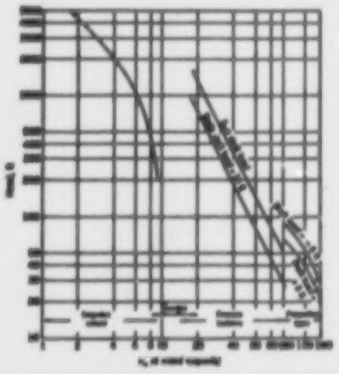
SMALL HYDRO POWER SYSTEM DIAGRAM

FIGURE 3-1



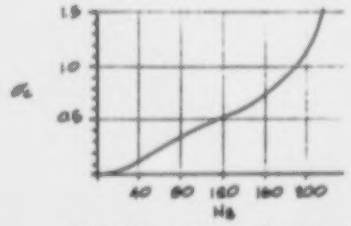
Maximum turbine efficiency as a function of specific speed. (Moody)

CHART A



Recommended limits of specific speed for turbines under various effective heads at sea level with water temperature at 80° F. (After Moody)

CHART B



RELATION BETWEEN CAVITATION PARAMETER σ_c AND TURBINE SPECIFIC SPEEDS N_S

CHART C

$$q_{(in)} = \frac{153.3\sqrt{H_{(ft)}}\ \phi}{N(RPM)}$$

$\phi \approx .45 - .48$ (IMPULSE)

$\phi \approx 0.6 - 0.9$ (FRANCIS)

$\phi \approx 1.4 - 2.0$ (PROPELLER)

DETERMINING RUNNER DIAMETER "D"

CHART D

DEFINITIONS

N_S = SPECIFIC SPEED = A NUMBER WHICH CLASSIFIES TURBINES AS TO TYPE. TWO TURBINES OF IDENTICAL GEOMETRICAL SHAPE BUT DIFFERENT SIZE WILL HAVE THE SAME SPECIFIC SPEED

N_{RPM} = MOST EFFICIENT OPERATING SPEED IN REVOLUTION /MIN.

TAILWATER = ELEVATION OF CHANNEL JUST DOWNSTREAM OF TURBINE

INSTRUCTIONS FOR TURBINE SELECTION

1. DETERMINE POWER AVAILABLE
   $P_{(HP)} = Q_{(cfs)} \times H_{(ft)} \times .1$ (CONVERSION FACTOR)
2. DETERMINE SPECIFIC SPEED
   $$N_S = \frac{N_{RPM}\sqrt{P_{(HP)}}}{(H_{(ft)})^{5/4}}$$
   CHOOSE N_{RPM} TO BE THE FASTEST SYNCHRONOUS SPEED POSSIBLE
   $N_{RPM} = \frac{7200}{i}$, WHERE i IS AN EVEN NUMBER
3. SELECT A TURBINE TYPE FROM CHART A AND CHART B
4. IF THE TURBINE SELECTED IS A FRANCIS OR PROPELLER, CHECK THE CAVITATION INDEX AND TAILWATER LEVEL TO ENSURE THAT THE TURBINE IS NOT SET TOO HIGH
   $$\underbrace{Z_1}_{\text{HGT. ABOVE TAILWATER}} = \underbrace{(33.1\ ft)}_{\text{VACUUM LIFT OF WATER AT SEA LEVEL 70°F}} - \sigma_c H(ft)$$
   σ_c FROM CHART
   IF THE TAILWATER SETTING IS UNWORKABLE, SELECT A SLOWER SPEED & REPEAT STEP C.
5. DETERMINE RUNNER DIAMETER (CHART D)
6. CONFIRM THE SELECTION WITH A MANUFACTURER.

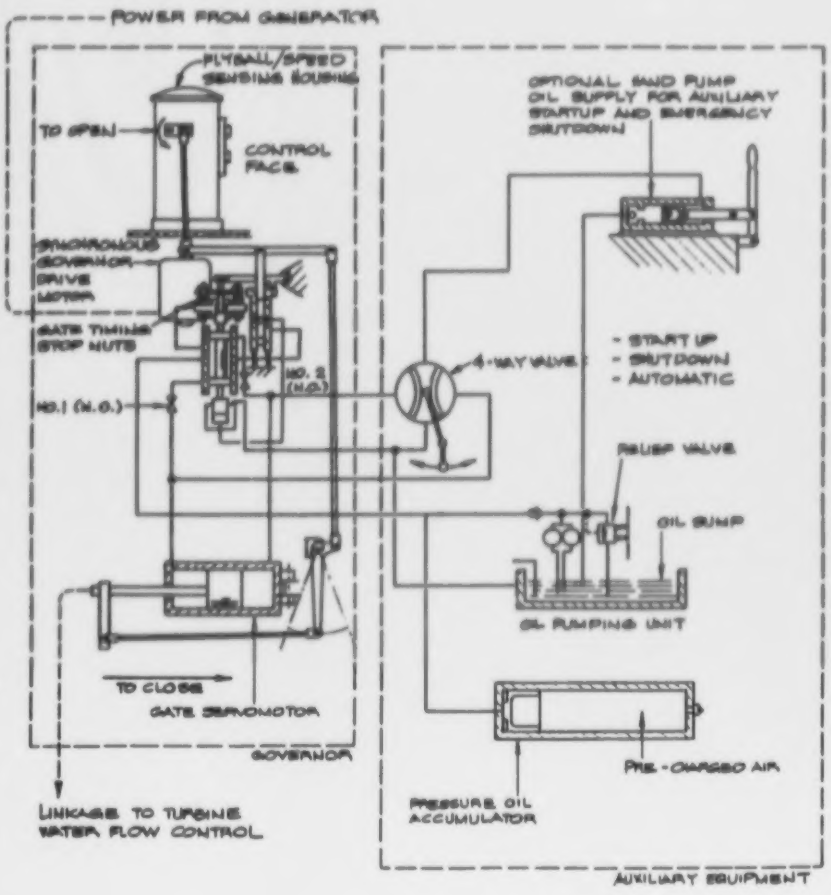
CONVERSIONS

DESIGN FLOW = Q IN cfs OR m^3/s
35.3 cfs = 1 m^3/s
HEAD ON TURBINE = H IN ft. OR m
3.28 ft. = 1m

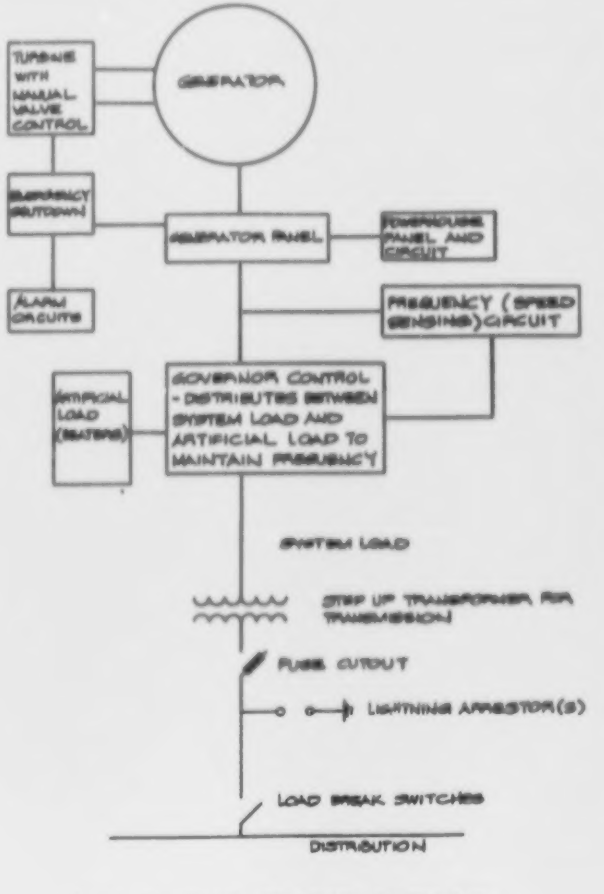
H IS ACTUALLY THE NET EFFECTIVE HEAD ON THE TURBINE BUT SUFFICIENT ACCURACY CAN BE OBTAINED AT THIS LEVEL BY TAKING THE DIFFERENCE BETWEEN THE INTAKE AND POWERHOUSE ELEVATIONS.

TURBINE APPLICATION CHART

FIGURE 3.2


POWER FROM GENERATOR
FLYBALL/SPEED SENSING HOUSING
TO OPEN
CONTROL FACE
SYNCHRONOUS GOVERNOR DRIVE MOTOR
GATE TIMING STOP NUTS
NO. 2 (N.O.)
NO. 1 (N.C.)
TO CLOSE
GATE SERVOMOTOR
GOVERNOR
LINKAGE TO TURBINE WATER FLOW CONTROL
OPTIONAL HAND PUMP OIL SUPPLY FOR AUXILIARY STARTUP AND EMERGENCY SHUTDOWN
4-WAY VALVE
- START UP
- SHUTDOWN
- AUTOMATIC
RELIEF VALVE
OIL SUMP
OIL PUMPING UNIT
PRE-CHARGED AIR
PRESSURE OIL ACCUMULATOR
AUXILIARY EQUIPMENT

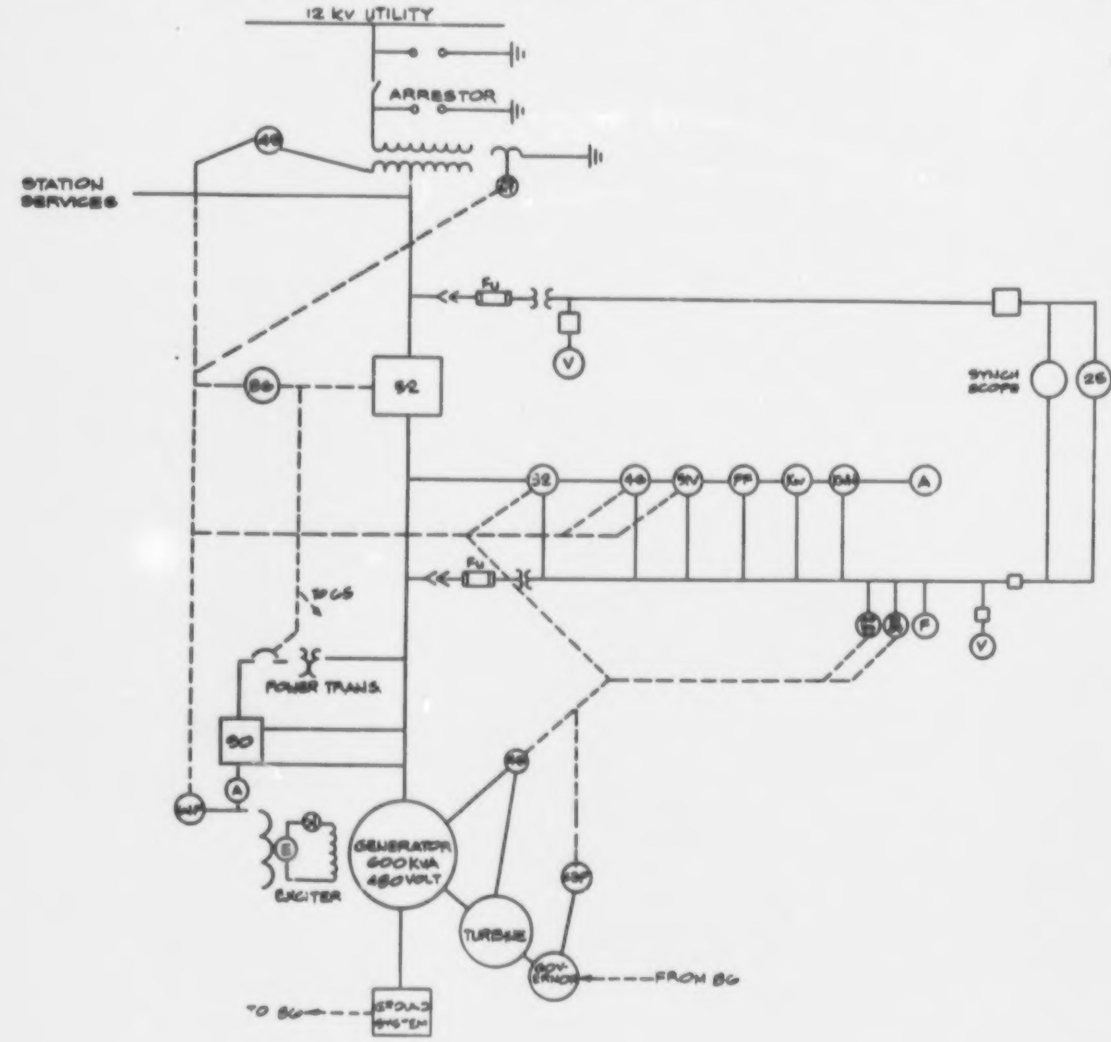
WOODWARD HYDRAULIC GATESHAFT GOVERNOR


TURBINE WITH MANUAL VALVE CONTROL
GENERATOR
EMERGENCY SHUTDOWN
GENERATOR PANEL
POWERHOUSE PANEL AND CIRCUIT
ALARM CIRCUITS
FREQUENCY (SPEED SENSING) CIRCUIT
ARTIFICIAL LOAD (HEATERS)
GOVERNOR CONTROL - DISTRIBUTES BETWEEN SYSTEM LOAD AND ARTIFICIAL LOAD TO MAINTAIN FREQUENCY
SYSTEM LOAD
STEP UP TRANSFORMER FOR TRANSMISSION
FUSE CUTOUT
LIGHTNING ARRESTOR(S)
LOAD BREAK SWITCHES
DISTRIBUTION

LOAD DUMPING GOVERNOR SCHEMATIC

GOVERNOR SYSTEMS

FIGURE 3-3


12 KV UTILITY
ARRESTOR
STATION SERVICES
52
Fu
V
32
46
51V
PF
KW
A
F
SYNCH SCOPE
25
POWER TRANS.
90
EXCITER
E
GENERATOR 600 KVA 480 VOLT
TURBINE
GOV-ERNOR
FROM 86
TO 86
GROUND SYSTEM

DEVICE LIST

DEVICE STANDARD CODE NO.	DESCRIPTION
25	SYNCH CHECK
32	REVERSE POWER
46	PHASE BALANCE, NEG. SEQ. OVERCURRENT
49	TEMPERATURE (WINDINGS, BEARINGS)
50/51T	TRANSFORMER GROUND OVER CURRENT
51V	VOLTAGE RESTRAINED TIME OVERCURRENT
52	MAIN BREAKER, AIR OR VACUUM
59/27	OVER/UNDER VOLTAGE
63P	LOW OIL PRESSURE
64F	EXCITER FIELD GROUND
81 OV	OVER/UNDER FREQUENCY
86	LOCKOUT RELAY
90	VOLTAGE REGULATOR WITH PARALLEL COMPENSATION

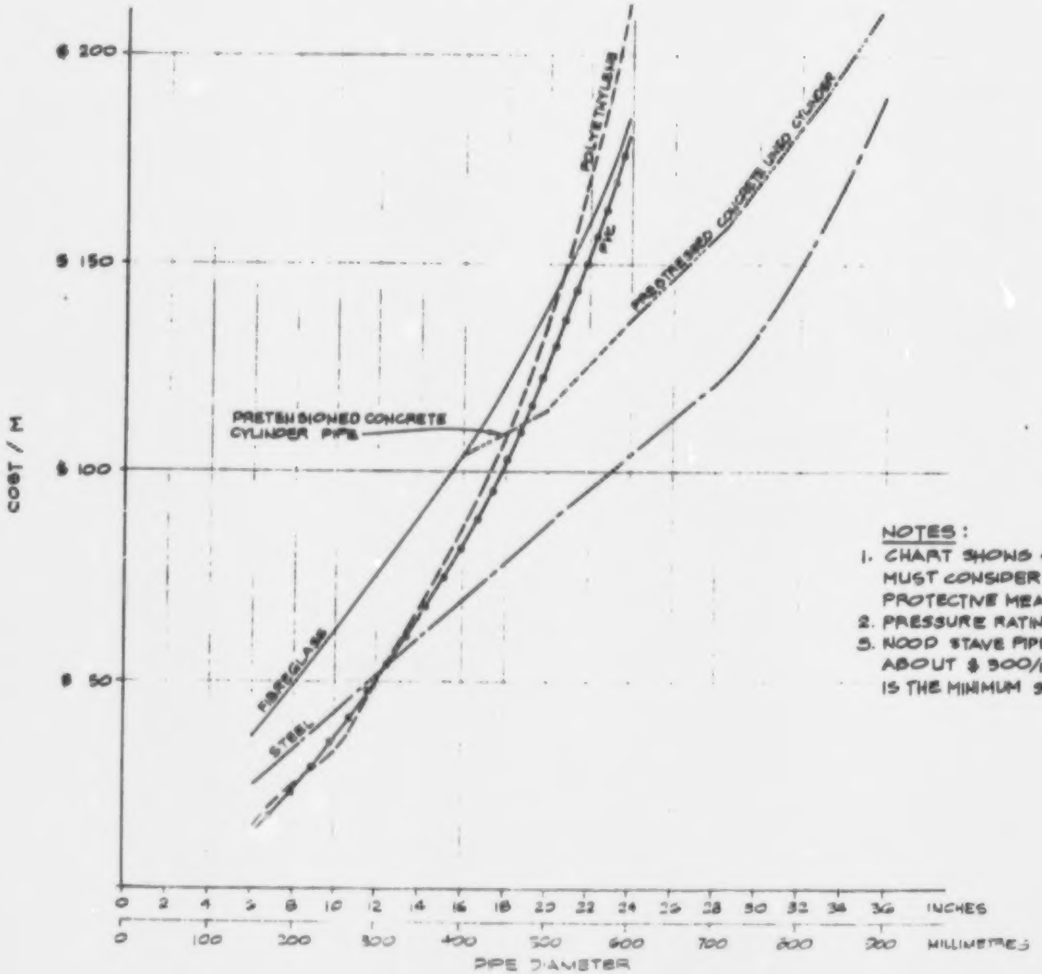
METERS

A	AMPERES
F	FREQUENCY
PF	POWER FACTOR
V	VOLTS
KW	KILOWATTS
KWH	KILOWATTHOUR

NOTE: THIS EXAMPLE IS BASED ON AN ACTUAL PROJECT. DIFFERENCES WILL OCCUR FOR DIFFERENT UTILITIES, GENERATOR OUTPUTS, LINE VOLTAGES AND LINE CLASSIFICATIONS.

TYPICAL PROTECTION SYSTEM

FIGURE 3.4



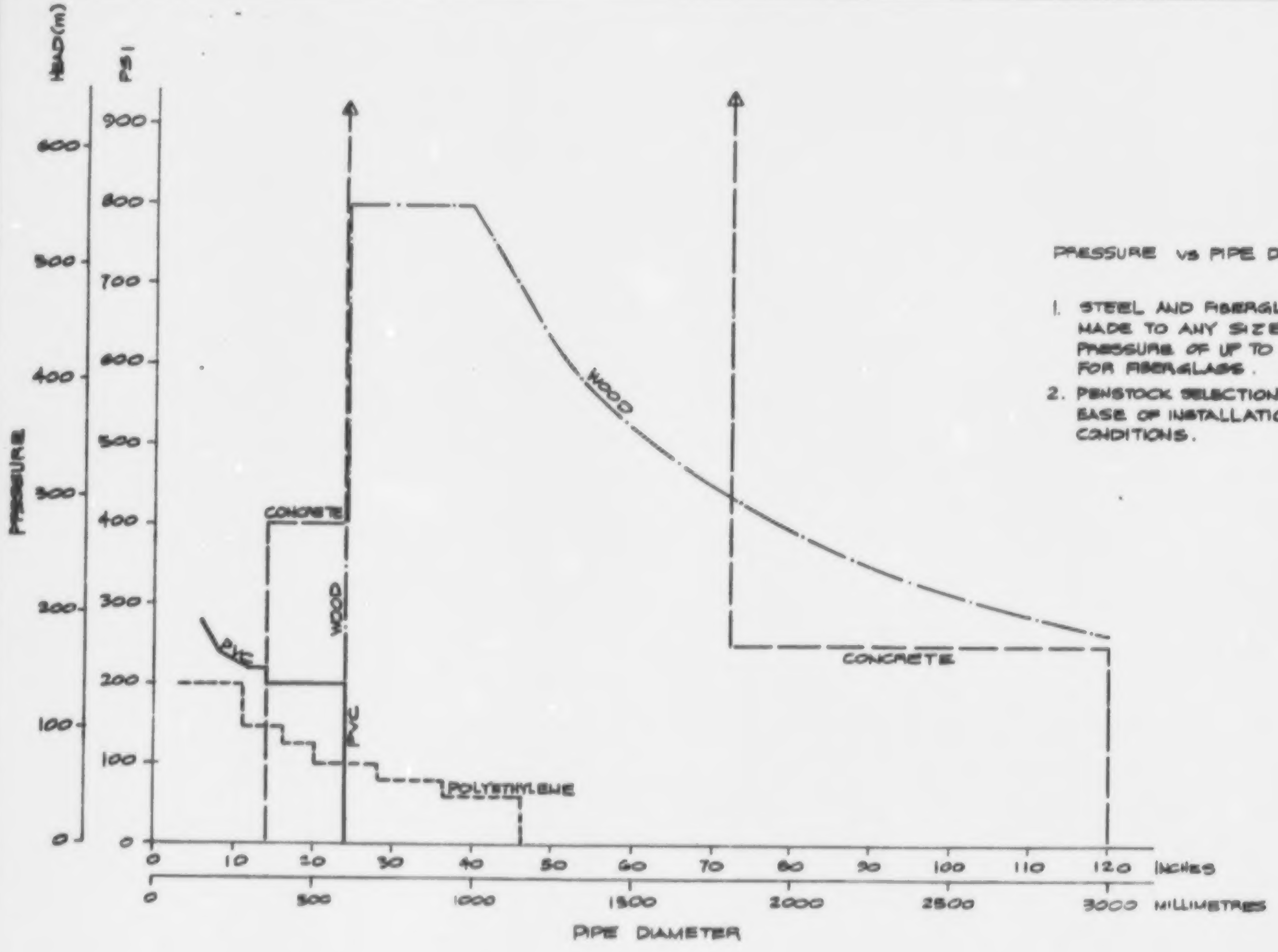
NOTES:

1. CHART SHOWS SUPPLY COST ONLY. INSTALLED COSTS MUST CONSIDER TERRAIN, EASE OF INSTALLATION, AND PROTECTIVE MEASURES.
2. PRESSURE RATING SHOWN IS 100 psi (700 Kpa)
3. WOOD STAVE PIPE NOT SHOWN. COST WOULD BE ABOUT $ 300/m FOR 600 mm Φ PIPE, WHICH IS THE MINIMUM SIZE MADE.

PENSTOCK COST DATA

FIGURE 3.5.1

5242 9C1

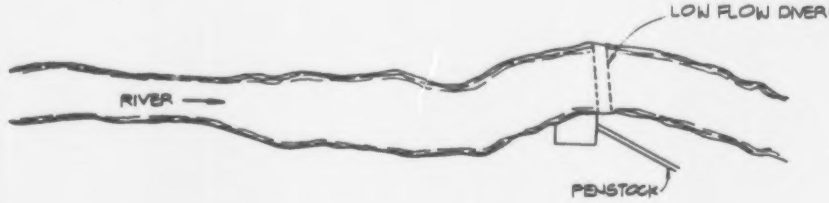


PRESSURE vs PIPE DIAMETER

1. STEEL AND FIBERGLASS PIPE CAN BE CUSTOM MADE TO ANY SIZE UP TO 6mϕ AND A PRESSURE OF UP TO 1050 kPa (150 psi) FOR FIBERGLASS.
2. PENSTOCK SELECTION MUST ALSO EVALUATE THE EASE OF INSTALLATION, DURABILITY AND TERRAIN CONDITIONS.

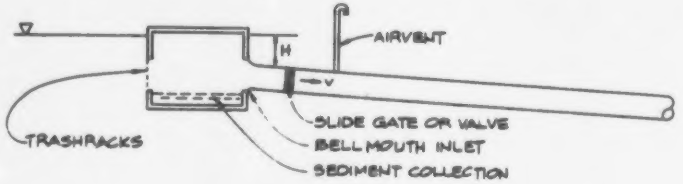
PENSTOCK APPLICATION CHART

FIGURE 3-5-2


LOW FLOW DIVERSION
RIVER →
PENSTOCK

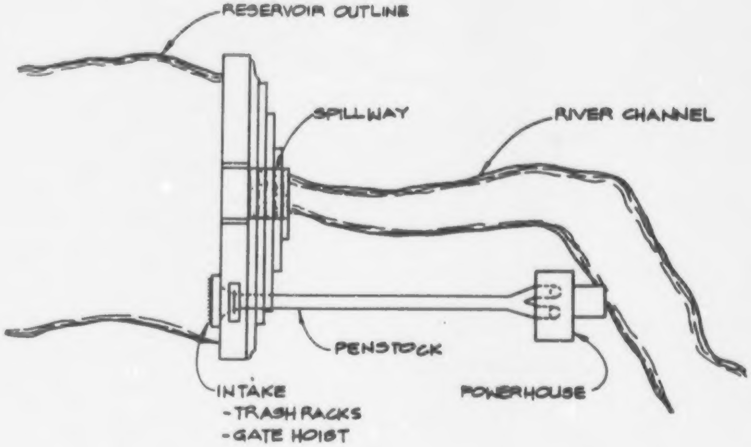
PLAN (SMALL RUN OF RIVER PLANT)
N.T.S

INTAKE SHOULD BE LOCATED IN :
- DEEP WATER TO AVOID FREEZING AND VORTICITY
- CALM WATER TO AVOID FRAZIL ICE
- AREAS WHERE THERE IS MINIMAL SEDIMENT DEPOSITION
- AREAS THAT ARE STABLE IN FLOODS


∇
H
AIRVENT
→ V
TRASHRACKS
SLIDE GATE OR VALVE
BELL MOUTH INLET
SEDIMENT COLLECTION

- ENSURE THAT VELOCITY THROUGH TRASH RACK IS LESS THAN 0.6 m/s
- ENSURE THAT Σ (HEADLOSSES + $\frac{V^2}{2g}$) ARE LESS THAN H

PROFILE
N.T.S.

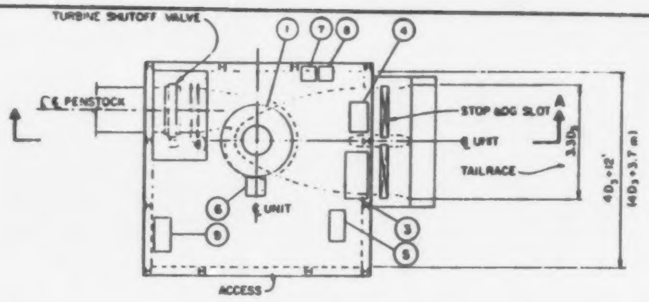

RESERVOIR OUTLINE
SPILLWAY
RIVER CHANNEL
PENSTOCK
POWERHOUSE
INTAKE
-TRASH RACKS
-GATE HOIST

PLAN (LARGE PLANT WITH STORAGE)
N.T.S.

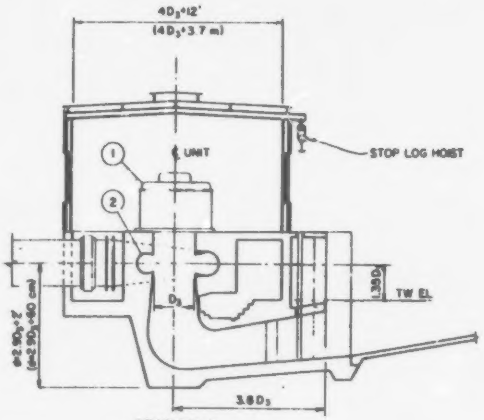
NOTES:

1. INTAKE DESIGN IS ENTIRELY SITE SPECIFIC. ALL ASPECTS OF THE RIVER AND THE SURROUNDING BANKS MUST BE CONSIDERED WHEN LOCATING THE INTAKE.
2. SURGE TANKS ARE NOT SHOWN. THEY REQUIRE SITE SPECIFIC DESIGN AND WOULD ONLY COMPRISE ABOUT 5 PERCENT OF PENSTOCK CONSTRUCTION COST, IF REQUIRED.

INTAKE DETAILS
FIGURE 3.6


TURBINE SHUTOFF VALVE
1
7
8
4
℄ PENSTOCK
STOP LOG SLOT
A
℄ UNIT
$3.3D_3$
TAILRACE
$4D_3+12'$
$(4D_3+3.7\ m)$
6
℄ UNIT
9
3
5
ACCESS

PLAN


$4D_3+12'$
$(4D_3+3.7\ m)$
1
℄ UNIT
STOP LOG HOIST
2
D_3
$1.3D_3$
TW EL
$\theta+2.9D_3+2'$
$(\theta+2.9D_3+60\ cm)$
$3.8D_3$

SECTION A

Equipment
1. Generator
2. Turbine
3. Governor
4. Generator Breaker
5. Control Panel
6. Neutral Ground Cubicle
7. Cooling Pumps
8. Sump Pumps
9. Air Compressor and Tank

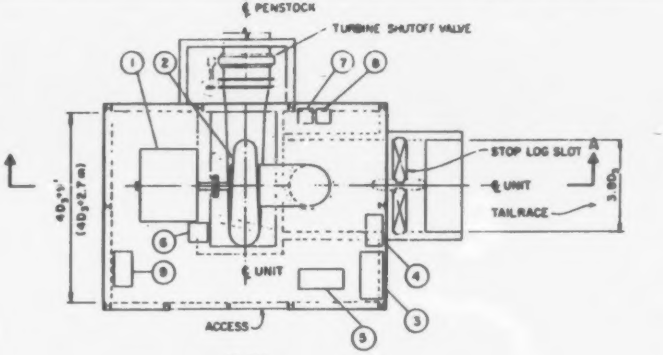
NOTES:
1. Arrangement and equipment are schematic.
2. Layout, equipment and dimensions shown may vary according to site specific power plant conditions.

POWERHOUSE LAYOUT 1

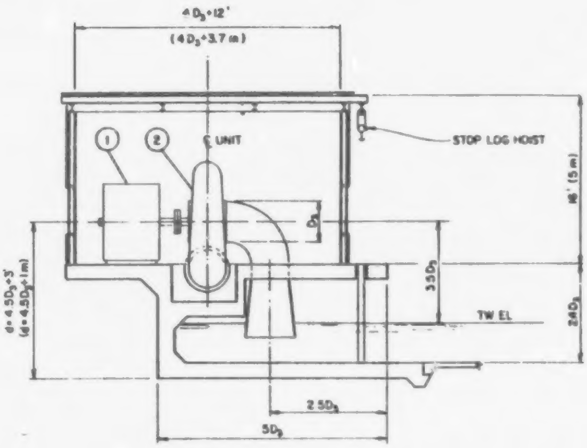
Powerhouse Layout — Vertical Francis Turbine
(WPRS - USA)

FIGURE 3·7·1

6848


℄ PENSTOCK
TURBINE SHUTOFF VALVE
①
②
⑦
⑧
STOP LOG SLOT
A
℄ UNIT
TAILRACE
$3.8D_3$
$4D_3+9'$
$(4D_3+2.7\text{ m})$
⑥
⑨
℄ UNIT
④
③
⑤
ACCESS

PLAN


$4D_3+12'$
$(4D_3+3.7\text{ m})$
①
②
℄ UNIT
STOP LOG HOIST
18' (5 m)
D_3
$3.5D_3$
$2.4D_3$
TW EL
$d=4.5D_3+3'$
$(d=4.5D_3+1\text{ m})$
$2.5D_3$
$5D_3$

SECTION A

Equipment

1. Generator
2. Turbine
3. Governor
4. Generator Breaker
5. Control Panel
6. Neutral Ground Cubicle
7. Cooling Pumps
8. Sump Pumps
9. Air Compressor and Tank

NOTES:

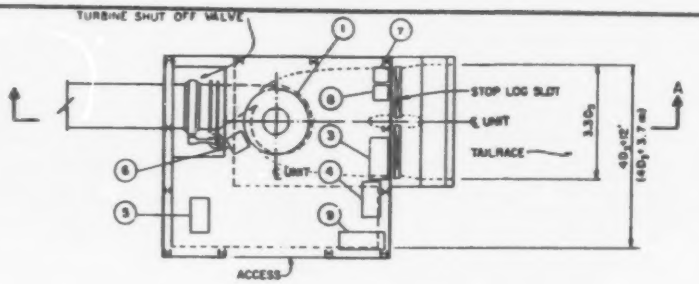
1. Arrangement and equipment are schematic.
2. Layout, equipment and dimensions shown may vary according to site specific power plant conditions.

POWERHOUSE LAYOUT 2

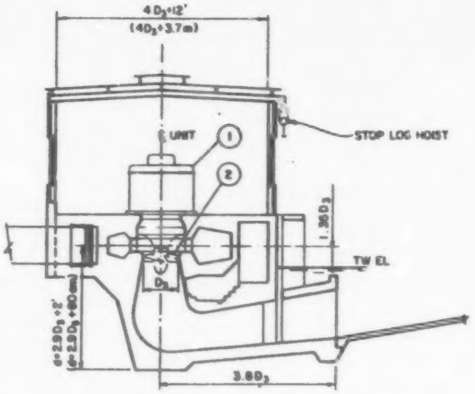
Powerhouse Layout — Horizontal Francis Turbine
(WPRS - USA)

FIGURE 3·7·2

5242
JUN 1982


TURBINE SHUT OFF VALVE
1
7
8
STOP LOG SLOT
℄ UNIT
3
TAILRACE
6
℄ UNIT
4
5
9
ACCESS
3.3D3
4D3+12'
(4D3+3.7m)
A

PLAN


4D3+12'
(4D3+3.7m)
℄ UNIT
1
2
STOP LOG HOIST
1.38D3
TW EL
D3
6+2.9D3+2'
(6+2.9D3+60mm)
3.8D3

SECTION A

Equipment

1. Generator
2. Turbine
3. Governor
4. Generator Breaker
5. Control Panel
6. Neutral Ground Cubicle
7. Cooling Pumps
8. Sump Pumps
9. Air Compressor and Tank

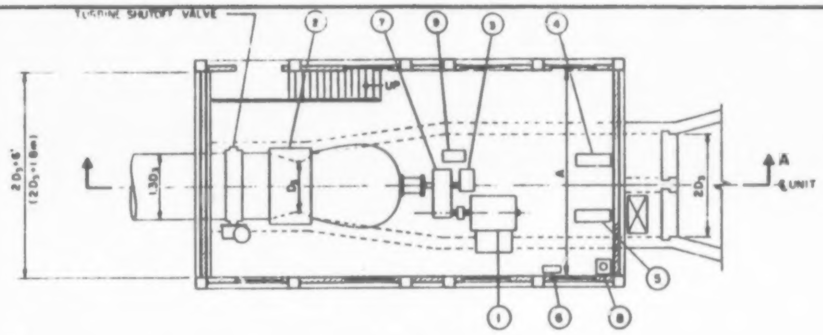
NOTES:

1. Arrangement and equipment are schematic.
2. Layout, equipment and dimensions shown may vary according to site specific power plant conditions.

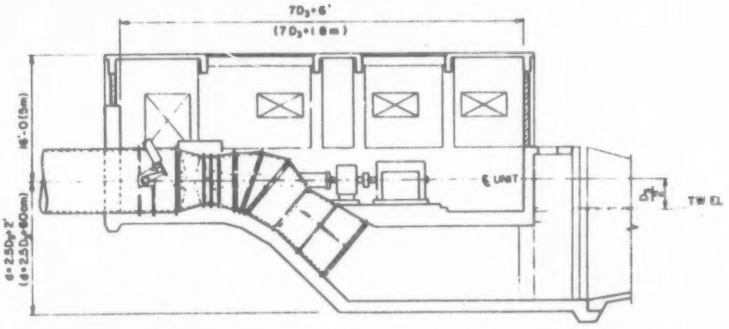
POWERHOUSE LAYOUT 3

Powerhouse Layout — Propeller Turbine with Penstock
(WPRS - USA)

FIGURE 3·7·3


TURBINE SHUTOFF VALVE
2
7
9
3
4
UP
$2D_3+6'$
$(2D_3+1.8m)$
$1.3D_3$
D_3
A
$2D_3$
A
℄ UNIT
5
1
6
8

PLAN


$7D_3+6'$
$(7D_3+1.8m)$
16'-0(5m)
$d+2.5D_3+2'$
$(d+2.5D_3+60cm)$
℄ UNIT
TW EL

SECTION A

Equipment
1. Generator
2. Turbine
3. Governor
4. Generator Breaker
5. Control Panel
6. Neutral Ground Cubicle
7. Speed Increaser
8. Sump Pumps
9. Pressure Set

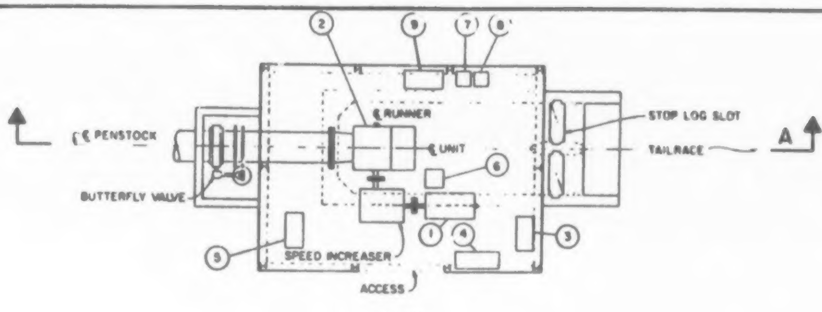
NOTES:
1. Arrangement and equipment are schematic.
2. Layout, equipment and dimensions shown may vary according to site specific power plant conditions.

POWERHOUSE LAYOUT 4

Powerhouse Layout — Tubular Turbine with Penstock
(WPRS - USA)

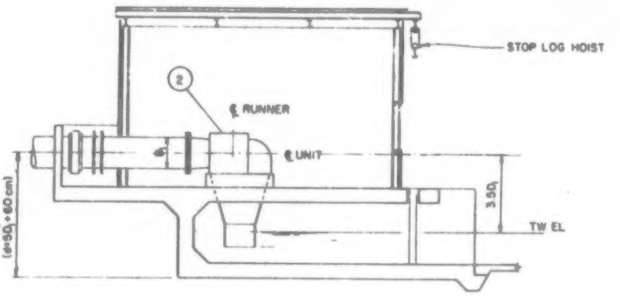
FIGURE 3-7-4

3242



2
9
7
8
℄ RUNNER
℄ PENSTOCK
℄ UNIT
STOP LOG SLOT
TAILRACE
A
6
BUTTERFLY VALVE
1
4
3
5
SPEED INCREASER
ACCESS

PLAN



STOP LOG HOIST
2
℄ RUNNER
℄ UNIT
ϕ50+Z
(ϕ=50+60cm)
3.50
TW EL

SECTION A

Equipment

1. Generator
2. Turbine
3. Governor
4. Generator Breaker
5. Control Panel
6. Neutral Ground Cubicle
7. Cooling Pumps
8. Sump Pumps
9. Air Compressor and Tank

NOTES:

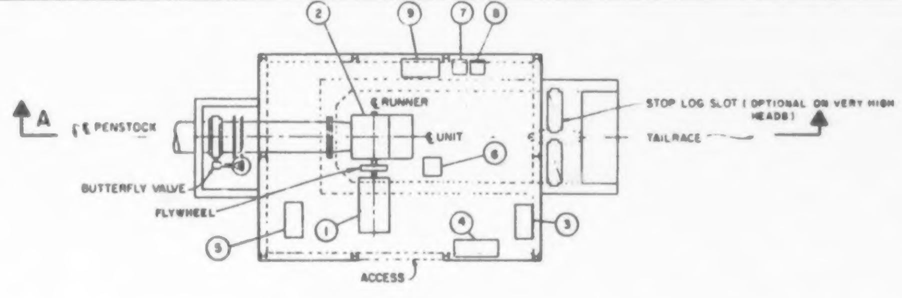
1. Arrangement and equipment are schematic.
2. Layout, equipment and dimensions shown may vary according to site specific power plant conditions.

POWERHOUSE LAYOUT 5

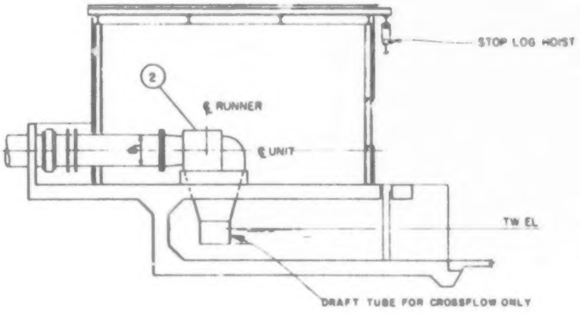
Powerhouse Layout — Crossflow Turbine (Low speed)
(WPRS - USA)

FIGURE 3·7·5

8242


2
9
7
8
℄ RUNNER
A
℄ PENSTOCK
℄ UNIT
STOP LOG SLOT (OPTIONAL ON VERY HIGH HEADS)
TAILRACE
6
BUTTERFLY VALVE
FLYWHEEL
5
1
4
3
ACCESS

PLAN


STOP LOG HOIST
2
℄ RUNNER
℄ UNIT
TW EL
DRAFT TUBE FOR CROSSFLOW ONLY

SECTION A

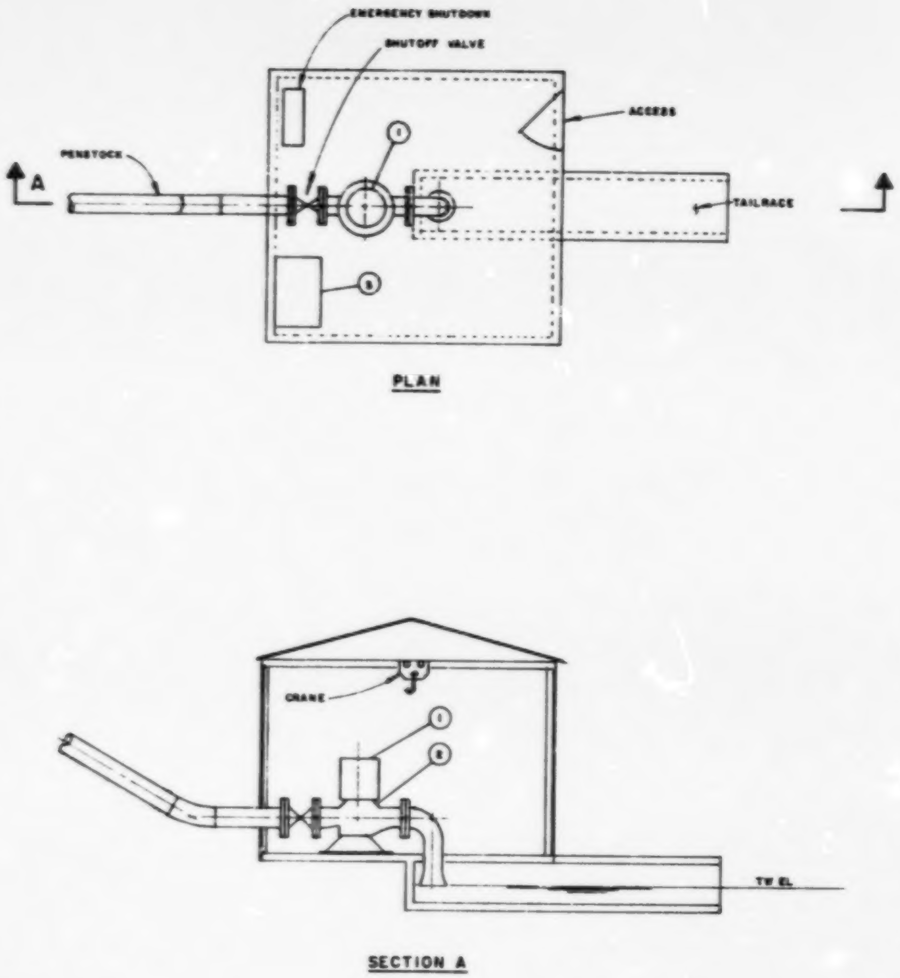
Equipment
1. Generator
2. Turbine
3. Governor
4. Generator Breaker
5. Control Panel
6. Neutral Ground Cubicle
7. Cooling Pumps
8. Sump Pumps
9. Air Compressor and Tank

NOTES:
1. Arrangement and equipment are schematic.
2. Layout, equipment and dimensions shown may vary according to site specific power plant conditions.

POWERHOUSE LAYOUT 6

Powerhouse Layout — Crossflow Turbine (High speed)
(WPRS-USA) or Pelton turbine

FIGURE 3·7·6


EMERGENCY SHUTDOWN
SHUTOFF VALVE
ACCESS
PENSTOCK
A
1
TAILRACE
3
PLAN
CRANE
1
2
TW EL
SECTION A

Equipment

1. Generator
2. Turbine
3. Control panel

NOTES

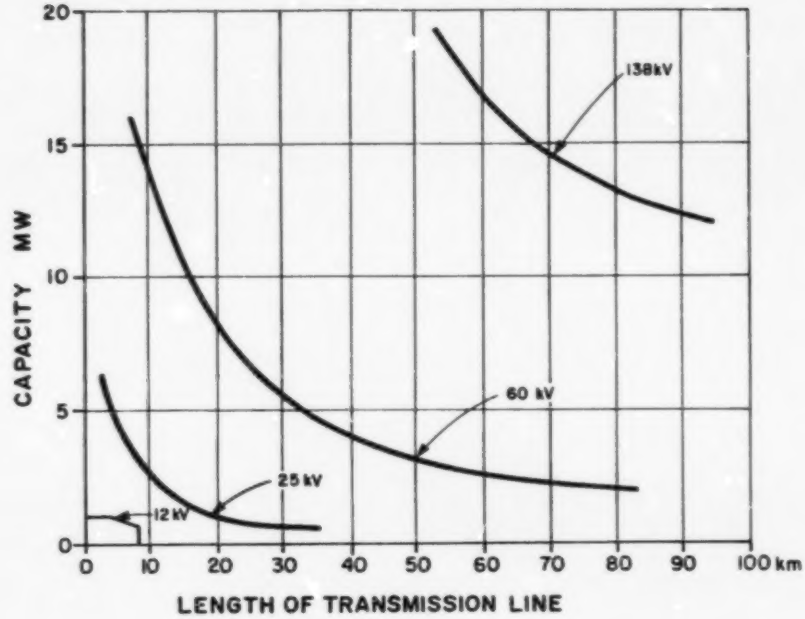
1. Arrangement and equipment are schematic.
2. Layout, equipment and dimensions shown may vary according to site specific power plant conditions.

POWERHOUSE LAYOUT 7

Powerhouse Layout - Reversible Pump/ Induction Generator for plant less than 50 Kw

FIGURE 3·7·7

5262



NOTES:

1. 20° C TEMPERATURE RISE
2. 10% POWER LOSS, 5% VOLTAGE DROP
3. THREE PHASE, 60 Hz
4. SWITCHING AND/OR SUBSTATION COSTS ARE SITE SPECIFIC, TO BE DETERMINED WITH LOCAL UTILITY

APPROXIMATE COSTS IN 1982 DOLLARS

12 kV - $50,000/km
25 kV - $50,000/km
60 kV - $60,000/km
138 kV - $80,000/km

TRANSMISSION LINE SIZING
FIGURE 3.8

LIST OF EQUIPMENT SUPPLIERS

TURBINES AND PACKAGES

CANADIAN

1. BARBER HYDRAULIC TURBINES
P O Box 340 Port Colburne, Ontario L3X 5W1

2. DEPENDABLE TURBINES
3005 Murray Street, Port Moody, B C V3H 1X3

3. DOMINION BRIDGE SULZER INC
P O Box 555 Lachine Quebec, Canada H8S 4E7

4. SMALL HYDRO ELECTRICS CANADA
P O Box 54 Silverton, B C V0G 2B0

5. SOLACE ENERGY CENTRE
2425 Main Street, Vancouver, B C

FOREIGN (Canadian Agent)

1. GILKES TURBINES (ELECTRIC POWER EQUIPMENT LTD)
1285 Homer Street, Vancouver, B C V6B 2Z2

2. THE JAMES LEFFEL AND CO LTD
426 East Street, Springfield, Ohio USA 45501

3. OSSBERGER TURBINES (GORDON RUSSELL LTD)
7600 Alderbridge Way, Richmond, B C V6X 2A2

4. VOEST/KOESLER TURBINES/
(INDUSTRIAL HEAT ENGINEERING LTD)
680 Raymur Avenue, Vancouver, B C V6A 2R1

GENERATORS

NOTE: Generator manufacturers must be given complete information on the turbine characteristics (preferably labelled drawings) before proper responses to enquiries can be made.

1. KATO ENGINEERING (FINNING POWER PRODUCTS)
   555 Great Northern Way, Vancouver, B C

2. SIMSON-MAXWELL LTD
   1380 W 6th Avenue, Vancouver, B C

3. SIMPSON POWER PRODUCTS
   5271 Regent, Burnaby, B C

GOVERNORS

1. WOODWARD GOVERNOR COMPANY
   5001 N Second Street, Rockford, Illinois USA 61101

2. THOMSON AND HOWE ENERGY SYSTEMS INC
   Site 17 Box 2 S.S. 1
   Kimberley B C V1A 2Y3

TURBINE DATA SHEET

LOCATION: ______________________ DATE ______________________

Address for Correspondence: ______________________

____

____

Flow of Water: ______________________

Gross and Net Head: ______________________

Power Requirement: ______________________

Length Diameter and Penstock Type: ______________________

Reservoir Capacity: ______________________

Isolated or Parallel Operation: ______________________

Number of Units: ______________________

Existing Facilities: ______________________

Manual or Automatic Operation ______________________

Elevation of Plant Above Sea Level ______________________

Desired Height above Tailwater ______________________

Sediment Content of Water Supply ______________________

Will the turbine run at partial loads for long periods? ______________________

GENERATOR DATA SHEET

GENERATOR

Model:	
Type:	
kW:	kV.A
Volts:	
Power Factor:	Phase
Wire:	Pole
Cycle:	RPM
Rotation:	
Outlet Location:	
Temp Rise:	
Bearings:	
Insulation:	
Coupling:	
Shaft Size:	
Exciter:	

PRIME MOVER DATA

Connection Details:

Maximum Speed (Runaway):

Flywheel Characteristics:

Common Base or Floor Mount:

CONTROL PANEL

Type:	Alarms
Location:	Annunciation
Meters Required:	Parallel Operation
Circuit Breaker:	Voltage Adjustment

APPENDIX 5

HYDROLOGY INFORMATION

APPENDIX 5

CONTENTS

FIGURES

5.1 ANNUAL PRECIPITATION

5.2.1 ANNUAL RUNOFF (SOUTHERN B C)

5.2.2 ANNUAL RUNOFF (NORTHERN B C)

5.3 FIRMNESS FACTORS

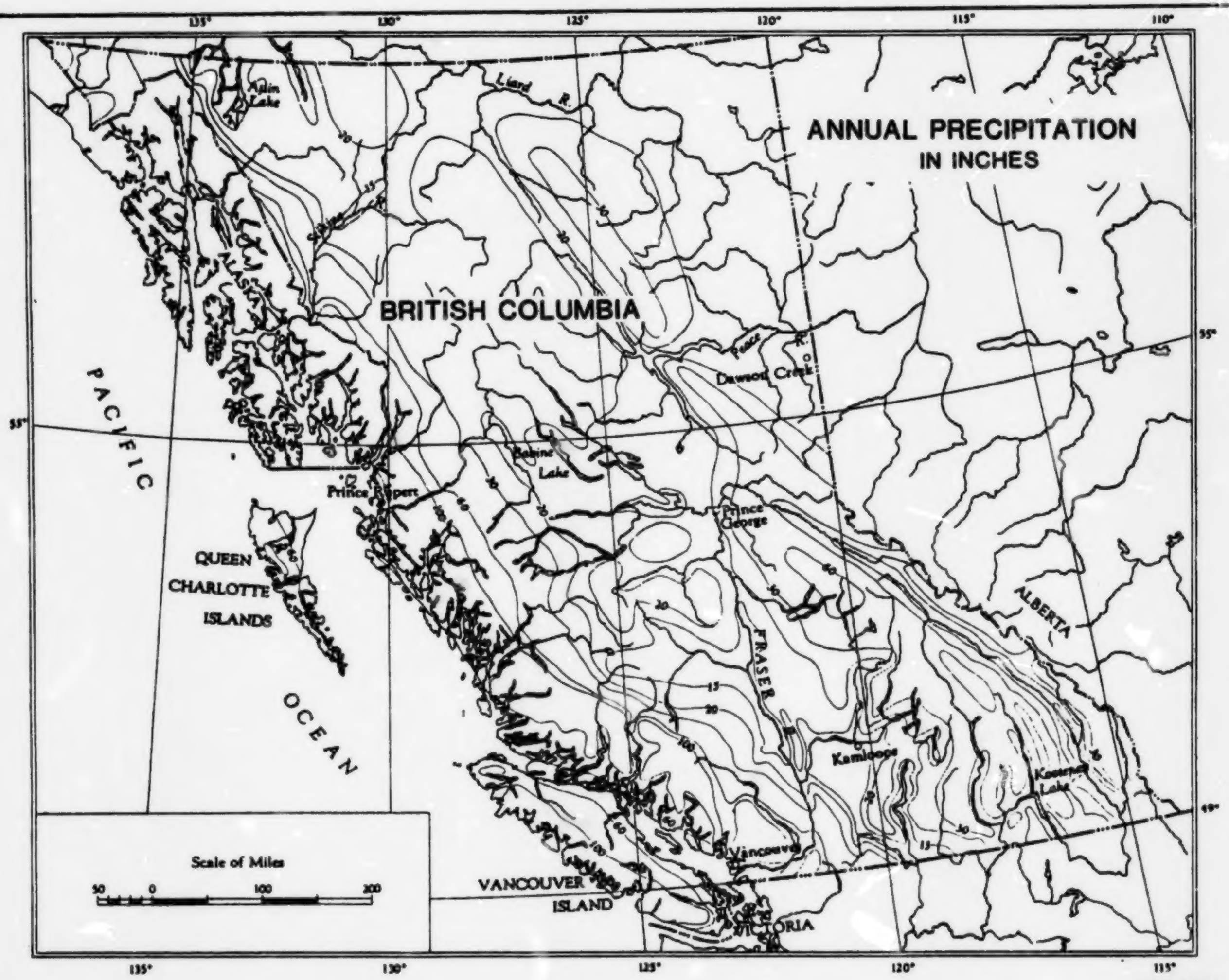
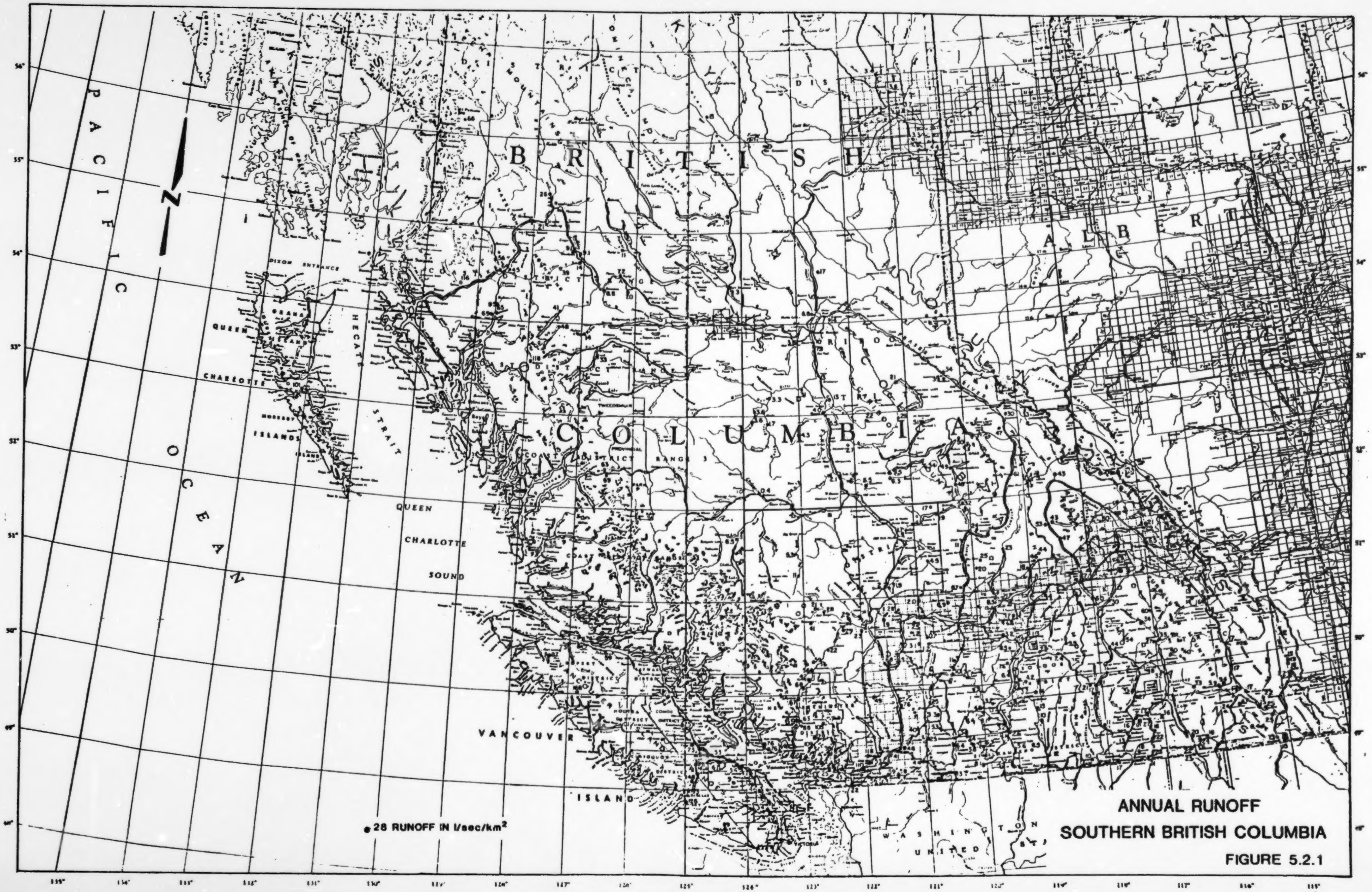

ANNUAL PRECIPITATION
IN INCHES
BRITISH COLUMBIA
ALBERTA
ALASKA
PACIFIC
OCEAN
QUEEN
CHARLOTTE
ISLANDS
VANCOUVER
ISLAND
VICTORIA
Vancouver
Kamloops
Kootenay Lake
FRASER
Prince George
Dawson Creek
Peace R.
Babine Lake
Prince Rupert
Atlin Lake
Liard R.
Scale of Miles
50
0
100
200
135°
130°
125°
120°
115°
110°
55°
49°
10
15
20
30
60
100

FIGURE 5.1

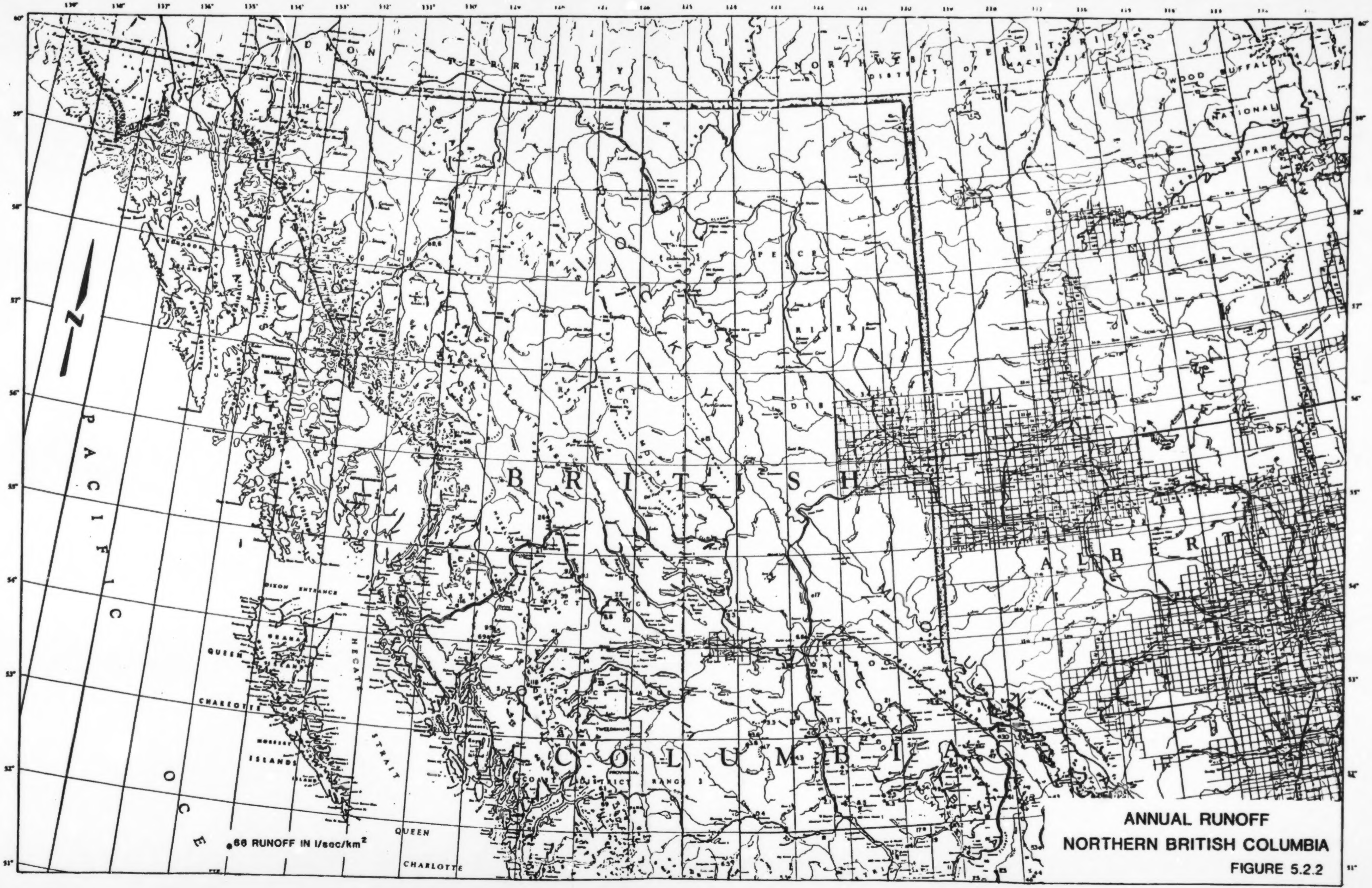
5242

UEC 1983

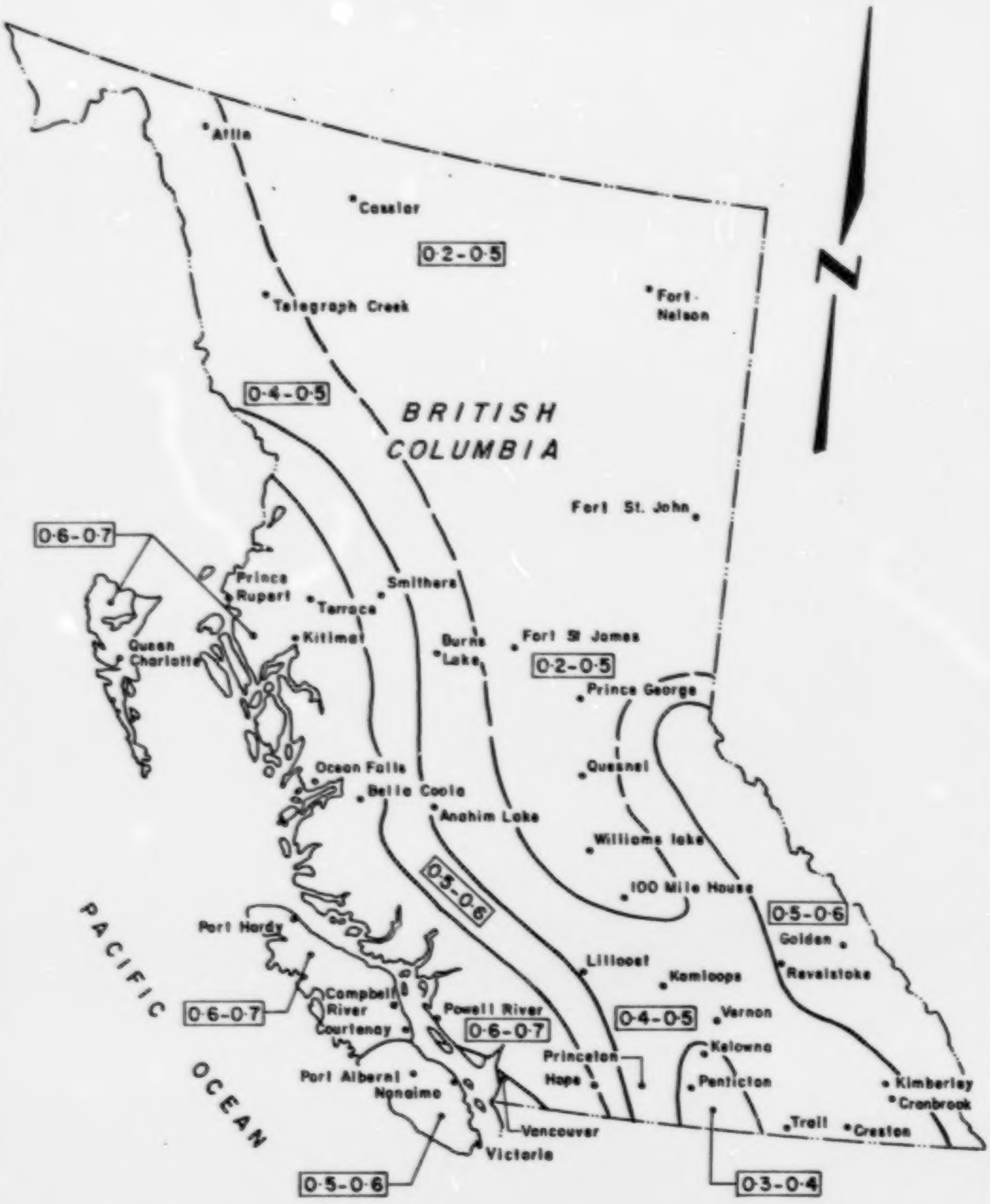

N
PACIFIC OCEAN
BRITISH COLUMBIA
ALBERTA
DIXON ENTRANCE
GRAHAM
QUEEN CHARLOTTE ISLANDS
MORESBY ISLAND
HECATE STRAIT
QUEEN CHARLOTTE SOUND
VANCOUVER ISLAND
WASHINGTON
UNITED STATES
TWEEDSMUIR PROVINCIAL
COAST DISTRICT RANGE 3
• 28 RUNOFF IN l/sec/km²
56°
55°
54°
53°
52°
51°
50°
49°
48°
135°
134°
133°
132°
131°
130°
129°
128°
127°
126°
125°
124°
123°
122°
121°
120°
119°
118°
117°
116°
115°

ANNUAL RUNOFF
SOUTHERN BRITISH COLUMBIA

FIGURE 5.2.1


N
PACIFIC OCEAN
YUKON TERRITORY
NORTHWEST TERRITORIES
DISTRICT OF MACKENZIE
WOOD BUFFALO NATIONAL PARK
BRITISH COLUMBIA
ALBERTA
PEACE RIVER
DIXON ENTRANCE
HECATE STRAIT
QUEEN CHARLOTTE
GRAHAM
MORESBY
ISLANDS
QUEEN CHARLOTTE
•66 RUNOFF IN l/sec/km²

ANNUAL RUNOFF
NORTHERN BRITISH COLUMBIA
FIGURE 5.2.2


N
BRITISH COLUMBIA
PACIFIC OCEAN
0·2–0·5
0·4–0·5
0·6–0·7
0·2–0·5
0·5–0·6
0·5–0·6
0·6–0·7
0·6–0·7
0·4–0·5
0·5–0·6
0·3–0·4
Atlin
Cassiar
Telegraph Creek
Fort Nelson
Fort St. John
Prince Rupert
Terrace
Smithers
Kitimat
Queen Charlotte
Burns Lake
Fort St James
Prince George
Quesnel
Ocean Falls
Bella Coola
Anahim Lake
Williams lake
100 Mile House
Golden
Revelstoke
Port Hardy
Campbell River
Courtenay
Powell River
Lillooet
Kamloops
Vernon
Kelowna
Penticton
Princeton
Hope
Port Alberni
Nanaimo
Vancouver
Victoria
Kimberley
Cranbrook
Trail
Creston

$$\text{FIRMNESS FACTOR} = \frac{\text{ANNUAL ENERGY (kWh)}}{\text{INSTALLED CAPACITY (kw)} \times 8760\ \text{hrs}}$$

FIRMNESS FACTORS
FIGURE 5.3

APPENDIX 4

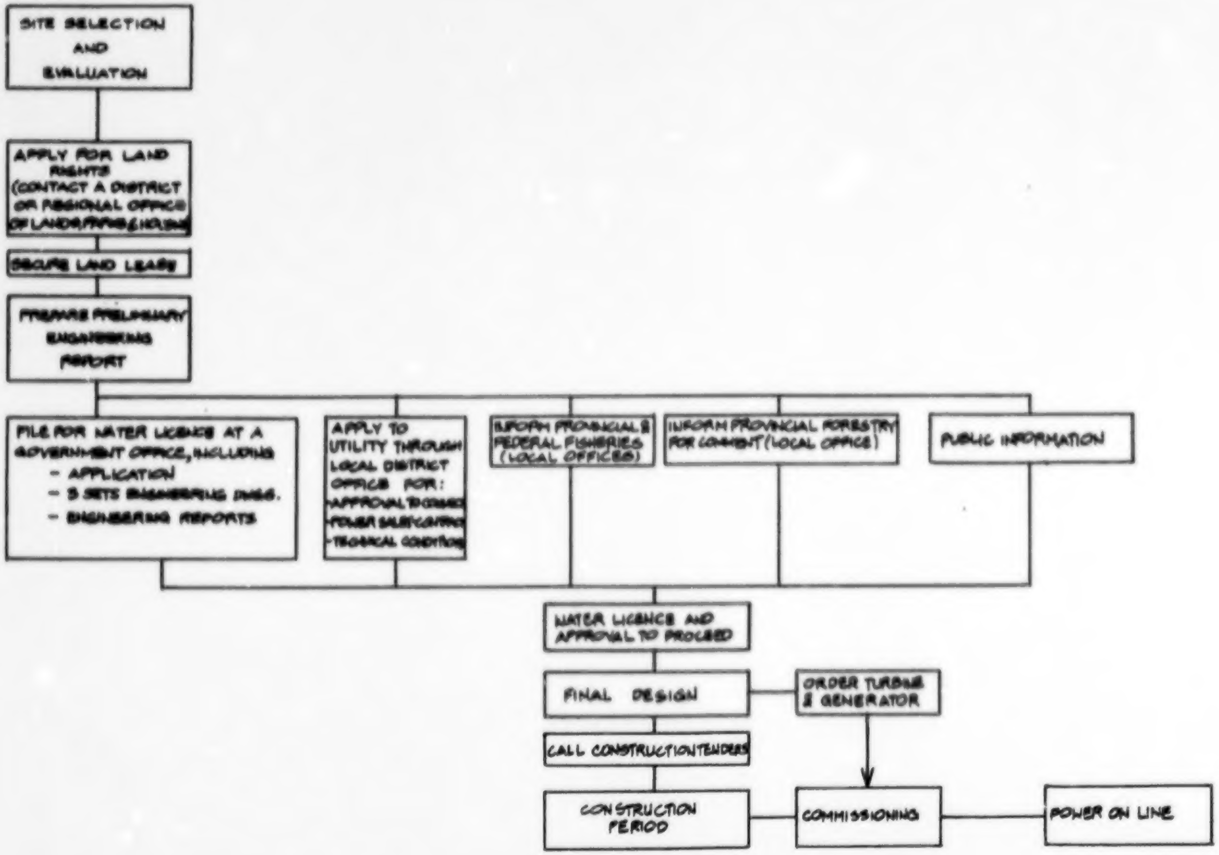
IMPLEMENTATION OF A SMALL HYDRO POWER PROJECT

APPENDIX 4

CONTENTS

FIGURE

4.1 IMPLEMENTATION OF A SMALL HYDRO POWER PROJECT


SITE SELECTION AND EVALUATION
APPLY FOR LAND RIGHTS (CONTACT A DISTRICT OR REGIONAL OFFICE OF LANDS,PARKS & HOUSING
SECURE LAND LEASE
PREPARE PRELIMINARY ENGINEERING REPORT
FILE FOR WATER LICENCE AT A GOVERNMENT OFFICE, INCLUDING
- APPLICATION
- 5 SETS ENGINEERING DWGS.
- ENGINEERING REPORTS
APPLY TO UTILITY THROUGH LOCAL DISTRICT OFFICE FOR:
-APPROVAL TO CONNEC
-POWER SALES CONTRAC
-TECHNICAL CONDITIONS
INFORM PROVINCIAL & FEDERAL FISHERIES (LOCAL OFFICES)
INFORM PROVINCIAL FORESTRY FOR COMMENT (LOCAL OFFICE)
PUBLIC INFORMATION
WATER LICENCE AND APPROVAL TO PROCEED
FINAL DESIGN
ORDER TURBINE & GENERATOR
CALL CONSTRUCTION TENDERS
CONSTRUCTION PERIOD
COMMISSIONING
POWER ON LINE

IMPLEMENTATION OF A SMALL HYDRO POWER PROJECT

FIGURE 4.1

POOR

QUALITY

ORIGINAL